UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	)	**Docket No. _______**
	)	

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARDS PRC-029-1 AND PRC-024-4

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval proposed Reliability Standard PRC-029-1 Frequency and Voltage Ride-through Requirements for Inverter-based Generating Resources, proposed Reliability Standard PRC-024-4 Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and 2 Wind Plants, and Synchronous Condensers, and the proposed definition of the term Ride-through for inclusion in the *Glossary of Terms used in NERC Reliability Standards*.[4] As discussed herein, the proposed Reliability Standards would advance the reliability of the Bulk-Power System ("BPS") by establishing voltage and frequency ride-through criteria for Generator Owners of Inverter-Based Resources ("IBR") to continue to inject current and perform voltage support during a BPS disturbance and prohibit momentary cessation in the no-trip zone during disturbances.

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1 16 U.S.C. § 824o.

2 18 C.F.R. § 39.5 (2024).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006) [hereinafter ERO Certification Order].

4 The *Glossary of Terms used in NERC Reliability Standards* ("NERC Glossary" or "Glossary") is available on the NERC website at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf. Unless otherwise indicated, all capitalized terms used in this petition shall have the meaning set forth in the NERC Glossary.

The proposed Reliability Standards are an integral part of NERC's proposed framework to address IBR performance issues in a comprehensive and holistic manner. The proposed Reliability Standards addressed in this filing are responsive to the Commission's directives in Order No. 901 directing NERC to submit new or revised standards addressing IBR ride-through performance requirements by November 4, 2024.[5] As discussed in detail below, the proposed Reliability Standards are part of a set of standards that collectively respond to the Commission's directives for requirements addressing IBR ride-through settings, ride-through performance, data recording, and analysis and mitigation of unexpected IBR performance. This proposed framework consists of the following standards and definitions:

- Proposed definition of the term Inverter-Based Resource, for inclusion in the *Glossary of Terms used in NERC Reliability Standards* (*separately filed, concurrently with this petition*);[6]
- Proposed Reliability Standard PRC-028-1 – Disturbance Monitoring and Reporting Requirements for IBR, with comprehensive disturbance monitoring and reporting requirements to IBR (*separately filed, concurrently with this petition*);
- Proposed Reliability Standard PRC-029-1 – Frequency and Voltage Ride-through Requirements for IBR, with capability and performance-based requirements for IBR Ride-through performance; and
- Proposed Reliability Standard PRC-030-1 – Unexpected Inverter-Based Resource Event Mitigation, requiring analysis and mitigation of IBR performance issues (*separately filed, concurrently with this petition*).

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5 Order No. 901, *Reliability Standards to Address Inverter-Based Resources*, 185 FERC ¶ 61,042 (2023) [hereinafter Order No. 901].

6 The proposed definition for this term, which is used throughout the proposed Reliability Standards addressed in the filing, as follows:

> **Inverter-Based Resource (IBR)**: A plant/facility consisting of individual devices that are capable of exporting Real Power through a power electronic interface(s) such as inverter or converter, and that are operated together as a single resource at a common point of interconnection to the electric system. IBRs include, but are not limited to, plants/facilities with solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell devices.

NERC requests that the Commission approve the proposed Reliability Standards, provided in Exhibit A hereto, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC also requests approval of: (1) the associated Implementation Plan (Exhibit B); the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (Exhibit F); and the retirement of currently effective Reliability Standard PRC-024-3.

As required by Section 39.5(a) of the Commission's regulations,[7] this petition presents the technical basis and purpose of the proposed Reliability Standards, a summary of the development history (Exhibit G), and a demonstration that the proposed Reliability Standards meet the criteria identified by the Commission in Order No. 672[8] (Exhibit C). The NERC Board of Trustees adopted the proposed Reliability Standards on October 8, 2024.

I. SUMMARY

Multiple NERC disturbance reports,[9] including those analyzing the Blue Cut Fire[10] and Canyon 2 Fire,[11] have demonstrated a risk to the reliability of the BPS when IBRs have failed to ride-through system disturbances. Across multiple system events, a widespread loss of generating resources – solar photovoltaic ("solar PV"), wind, synchronous generation, and battery energy

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[7] 18 C.F.R. § 39.5(a).

[8] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC 61,104 at PP 262, 321-37 (2006) [hereinafter Order No. 672], *order on reh'g*, Order No. 672-A, 114 FERC 61,328 (2006).

[9] *See* Event Reports involving IBRs entering into momentary cessation or tripping in the aggregate: (1) the Blue Cut Fire (August 16, 2016); (2) the Canyon 2 Fire (October 9, 2017); (3) Angeles Forest (April 20, 2018); (4) Palmdale Roost (May 11, 2018); (5) San Fernando (July 7, 2020); (6) the first Odessa, Texas event (May 9, 2021); (7) the second Odessa, Texas event (June 26, 2021); (8) Victorville (June 24, 2021); (9) Tumbleweed (July 4, 2021); (10) Windhub (July 28, 2021); (11) Lytle Creek (August 26, 2021), and (12) Panhandle Wind Disturbance (March 22, 2022), https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx.

[10] NERC, *1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report, Southern California 8/16/2016 Event* (Blue Cut Fire Disturbance Report) (June 2017), https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf.

[11] Joint NERC and WECC Staff Report, *900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report* (Canyon 2 Fire Disturbance Report) (Feb. 2018), https://www.nerc.com/pa/rrm/ea/October%209%202017%20Canyon%202%20Fire%20Disturbance%20Report/900%20MW%20Solar%20Photovoltaic%20Resource%20Interruption%20Disturbance%20Report.pdf.

storage systems ("BESS") – have abnormally tripped, ceased current injection, or reduced power output with control interactions. BPS-connected generating resources remaining connected during normal and contingency conditions is a critical component of BPS reliability; the unexpected loss of widespread generating assets poses a significant risk to BPS reliability. Generator ride-through is a foundational essential reliability service. Ensuring fault ride-through capability enables dynamic reactive power support, frequency response, and other services.

For this reason, NERC identified the need for a comprehensive Ride-through Reliability Standard for IBRs.[12] This need was further reinforced when the Commission issued Order No. 901, directing the development of new or modified Reliability Standards to address risks associated with IBRs, including new requirements for disturbance monitoring data sharing, IBR performance requirements, and post-event performance validation.

Proposed Reliability Standard PRC-029-1 would address the important reliability issue of IBR Ride-through performance through capability and performance-based requirements for IBRs. Consistent with the relevant Commission directives in Order No. 901, proposed PRC-029-1 would advance reliability by: (1) establishing a clear understanding of what it means for a generator to Ride-through a disturbance; (2) establishing voltage and frequency Ride-through criteria for IBRs to prevent the unnecessary tripping and momentary cessation of current due to phase lock loop loss of synchronism; and (3) ensuring that post-disturbance ramp rates return to pre-disturbance levels.

With the development of proposed Reliability Standard PRC-029-1 addressing IBRs, it became necessary to revise the applicability of currently effective Reliability Standard PRC-024-3, which addresses frequency and voltage settings for generating resources. Proposed Reliability

12 *See* Exhibit G, Complete Record of Development at item 17.

Standard PRC-024-4 would revise the applicable facility types to exclude IBRs and to include type 1 and type 2 wind resources and synchronous condensers. NERC determined there is no reliability need to impose actual disturbance Ride-through requirements on these resources, and that restrictions for frequency and voltage protection setting ranges would continue to be appropriate. Together the proposed Reliability Standards would help ensure that applicable BPS connected resources would Ride-through system disturbances and avoid the negative reliability impacts associated with unnecessary tripping and momentary cessation.

For these reasons, which are summarized here and stated more fully below, NERC requests that the Commission approve the proposed Reliability Standards and Ride-through definition, provided in Exhibit A hereto, as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[13]

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[13] Persons to be included on the Commission's service list are indicated with an asterisk. NERC requests waiver of 18 C.F.R. § 385.203(b) to permit the inclusion of more than two people on the service list.

III. REGULATORY BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[14] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the BPS, and with the duty of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1) of the FPA states that all users, owners, and operators of the BPS in the United States will be subject to Commission-approved Reliability Standards.[15] Section 215(d)(5) of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard.[16] Section 39.5(a) of the Commission's regulations requires the ERO to file for Commission approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes to make effective.[17]

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the BPS and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA and Section 39.5(c) of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.[18]

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[14] 16 U.S.C. § 824o.

[15] *Id.* § 824(b)(1).

[16] *Id.* § 824o(d)(5).

[17] 18 C.F.R. § 39.5(a).

[18] 16 U.S.C. § 824o(d)(2); 18 C.F.R. § 39.5(c)(1).

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standards were developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[19] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[20] In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain criteria for approving Reliability Standards.[21] The development process is open to any person or entity with a legitimate interest in the reliability of the BPS. NERC considers the comments of all stakeholders. Further, a vote of stakeholders and adoption by the NERC Board of Trustees is required before NERC submits the Reliability Standard to the Commission for approval.

IV. THE NEED FOR RIDE-THROUGH STANDARDS ADDRESSING INVERTER-BASED RESOURCES

A. Disturbances on the BPS Indicate that IBRs are Failing to Ride-through as they Should to Maintain Reliability.

In 2017, following a series of grid disturbances involving IBRs, NERC developed the Inverter-Based Resources Performance Task Force, or IRPTF. This group undertook a comprehensive review of all NERC Reliability Standards to determine if there were opportunities to address gaps or otherwise improve the standards to assure reliability considering the unprecedented growth of IBRs on the BPS.

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[19] Order No. 672 at P 334.

[20] The NERC Rules of Procedure, including Appendix 3A, NERC Standard Processes Manual, are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

[21] ERO Certification Order at P 250.

In 2019, the IRPTF published a white paper summarizing its work. Among other things, the IRPTF highlighted issues with the then effective PRC-024 Reliability Standard, PRC-024-2 - Generator Frequency and Voltage Protective Relay Settings.[22] In this white paper, the IRPTF found that misinterpretation of the requirements of Reliability Standard PRC-024-2 led to the intentional and unnecessary tripping of solar PV resources during the Blue Cut Fire[23] and Canyon 2 Fire[24] disturbances because some entities misinterpreted the area outside of the "No Trip" curve as a "Must-Trip" requirement instead of as a "May-Trip" zone. The intent of the PRC-024-2 voltage ride-through requirement was to define the minimum and maximum voltage conditions where generating resources may trip from protective relaying for voltage excursions. The IRPTF recommended that clarifications to the standard be made so entities would know that being outside a "No-Trip" zone does not mean the unit must trip, but rather it may trip to protect its equipment.

To address this misinterpretation, NERC initiated Project 2018-04 Modifications to PRC-024-2 to address the IRPTF recommendations. Project 2018-04 Modifications to PRC-024-2 developed the currently effective version of the PRC-024 Reliability Standard, PRC-024-3 - Frequency and Voltage Protection Settings for Generating Resources in 2019 that the Commission approved in 2020.[25]

B. NERC Efforts to Address Reliability Risks with IBRs failing to Ride-Through System Disturbances.

While Reliability Standard PRC-024-3 addressed the misinterpretation identified in the IRPTF report, events were still occurring following its development where IBRs were failing to

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22 NERC IRPTF PRC-024-2 Gaps Whitepaper (Mar. 2020), https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/NERC_IRPTF_PRC-024-2_Gaps_Whitepaper_FINAL_CLEAN.pdf [hereinafter "IRPTF White Paper"].

23 Blue Cut Fire Disturbance Report *supra* note 10.

24 Canyon 2 Fire Disturbance Report, *supra* note 11.

25 *N. Am. Elec. Reliability Corp.,* Docket No. RD20-7-000 (July 9, 2020). Reliability Standard PRC-024-3 became effective in the United States on October 1, 2022.

Ride-through a disturbance.[26] These events made it clear that additional Reliability Standard requirements were needed to comprehensively address the issue of IBRs failing to Ride-through system disturbances. Reliability Standard PRC-024-3 is an equipment settings standard focused solely on voltage and frequency protection, and, in turn, does not address risks associated with IBR Ride-through capabilities.

In 2022, following its analysis of over 10 disturbances involving widespread loss of IBRs, NERC revised and repurposed an existing project to modify the PRC-024 standard, Project 2020-02 Transmission Connected Resources, to address IBR Ride-through performance. The purpose of Project 2020-02 Modifications to PRC-024 (Generator Ride-Through) was to retire Reliability Standard PRC-024-3 and replace it with a performance-based Ride-through standard that ensures generators remain connected to the BPS during system disturbances. The Standard Authorization Request for the project provided:

> Across all events, a widespread loss of generating resources – solar PV, wind, synchronous generation, and battery energy storage systems (BESS) – have abnormally tripped, ceased current injection, or reduced power output with control interactions. Generator ride-through is a foundational essential reliability service. BPS-connected generating resources remaining connected during normal and contingency conditions is a critical component of BPS reliability. Ensuring fault ride-through capability enables dynamic reactive power support, frequency response, and other services. The unexpected loss of widespread generating assets poses a significant risk to BPS reliability.[27]

The Project 2020-02 drafting team determined that Ride-through performance requirements for IBRs should be addressed by a separate standard from synchronous resources because of the different natures of synchronous resources and IBRs, including their risks, performance, and equipment capabilities. During the drafting team's development of a performance-based standard for IBRs in proposed Reliability Standard PRC-029-1, the

[26] Event Reports, supra note 9.
[27] *See* Exhibit G, Complete Record of Development at item 17.

Commission issued Order No. 901, directing the development of Reliability Standards for IBRs, including Reliability Standards to address IBR ride through performance. Accordingly, development of proposed Reliability Standard PRC-029-1 was aligned with the Commission's directives in Order No. 901 related to performance requirements for registered IBRs, which are described further below.

C. Order No. 901 Directs NERC to Develop Reliability Standards to Address Concerns Related to IBRs at "All Stages of Interconnection, Planning, and Operations"

On October 19, 2023, the Commission issued Order No. 901,[28] directing the development of Reliability Standards to address IBRs. In Order 901, and preceding Notice of Proposed Rulemaking, the Commission cites multiple ERO resources on IBR issues, including reliability guidelines, white papers, reliability assessments, technical reports, event reports, NERC alerts, and other resources, as underscoring the need for mandatory Reliability Standards to address reliability concerns related to IBRs at "all stages of interconnection, planning, and operations."[29] While the Commission acknowledged that NERC and industry groups had efforts underway to address the reliability risks associated with IBRs, the Commission directed NERC to address specific reliability gaps because the existing Reliability Standards do not adequately address the reliability risks posed by the increasing numbers of IBRs connecting to the BPS.[30] The Commission directed NERC to develop new and revised Reliability Standards to address the following four topic areas

[28] *See* Order No. 901.

[29] *Id.* at P 25.

[30] *Id.* at Section III.

of IBR issues: (1) data sharing;[31] (2) data and model validation;[32] (3) planning and operational studies;[33] and (4) performance requirements.[34]

Within these four topic areas, the Commission identified the specific reliability issues that must be addressed. In so doing, the Commission distinguished between IBRs currently registered with NERC for compliance purposes, or will be in the future based on the approved revisions in the IBR Registration Approval Order ("registered IBRs");[35] IBRs that are not registered with NERC ("unregistered IBRs") but which need to be modeled for reliability; and IBRs that are connected to the distribution system, but, in the aggregate, can impact BES reliability ("IBR-DERs").[36] NERC was directed to develop responsive standards and submit them to the Commission on a three-year, staggered timeframe.

With respect to the implementation of the directed standards modifications, the Commission stated, "we believe that there is a need to have all of the directed Reliability Standards effective and enforceable well in advance of 2030 and direct NERC to ensure that the associated implementation plans sequentially stagger the effective and enforceable dates to ensure an orderly industry transition for complying with the IBR directives in this final rule prior to that date."[37]

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31 *See* Order No. 901 at PP 66-109 (discussion of directives related to data sharing requirements).

32 *See id.* at PP 110-161 (discussion of directives related to data and model validation requirements).

33 *See id.* at PP 162-177 (discussion of directives related to planning and operational studies requirements).

34 *See id.* at PP 178-211 (discussion of directives related to performance requirements).

35 On November 22, 2022, the Commission issued an order directing NERC to undertake actions to expand the class of IBRs that are required to register with NERC and comply with NERC Reliability Standards. *Registration of Inverter-Based Resources*, 181 FERC ¶ 61,124 (2022) [hereinafter IBR Registration Order]. Specifically, the Commission directed NERC to explain how it will identify and register owners and operators of IBRs that are connected to the Bulk-Power System, but are not required to register with NERC under the Bulk Electric System definition, that have an aggregate material impact on the reliable operation of the Bulk-Power System." *Id.* at P 1.

The Commission approved NERC's proposed expansion of the Generator Owner and Generator Operator registry criteria to encompass additional IBRs in an order issued June 27, 2024. *Order Approving Revisions to North American Electric Reliability Corporation Rules of Procedure and Requiring Compliance Filing*, 187 FERC ¶ 61,196 (2024) [hereinafter IBR Registration Approval Order].

36 Order No. 901 at P 4 n.14.

37 Order No. 901 at P 226.

Additionally, the Commission directed NERC to submit an informational filing, within 90 days of the date of the order, detailing a comprehensive standards development plan and explanation of how NERC would prioritize the development of new or modified Reliability Standards.[38] This work plan is described in Section V *infra*.

1. Order No. 901 Ride-through Directives

Citing the NERC disturbance reports and white papers, the Commission directed NERC to develop new or revised Reliability Standards to require Generator Owners of registered IBRs to meet ride-through performance requirements. The Commission stated:

> Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults. The new or modified Reliability Standards must require registered IBRs to continue to inject current and perform frequency support during a Bulk-Power System disturbance. Any new or modified Reliability Standard must also require registered IBR generator owners and operators to prohibit momentary cessation in the no-trip zone during disturbances. NERC must submit new or modified Reliability Standards that establish IBR performance requirements, including requirements addressing frequency and voltage ride through, post-disturbance ramp rates, phase lock loop synchronization, and other known causes of IBR tripping or momentary cessation.[39]

The Commission recognized that there may be instances where an exemption to the ride-through requirements may be necessary and directed NERC to consider if such an exemption would be appropriate in its standard development process as follows:

> Therefore, we direct NERC through its standard development process to determine whether the new or modified Reliability Standards should provide for a limited and documented exemption

[38] Order No. 901 at P 222.

[39] *Id.* at P 190.

> for certain registered IBRs from voltage ride-through performance requirements. Any such exemption should be only for voltage ride-through performance for those existing IBRs that are unable to modify their coordinated protection and control settings to meet the requirements without physical modification of the IBRs' equipment.[40]

The Commission also directed that if NERC determined that an exemption was necessary from Ride-through requirements, to develop standards to mitigate the reliability impacts of said exemption as follows:

> Pursuant to section 215(d)(5) of the FPA, we modify the NOPR proposal. To the extent NERC determines that a limited and documented exemption for those registered IBRs currently in operation and unable to meet voltage Ride-through requirements is appropriate due to their inability to modify their coordinated protection and control settings, we direct NERC to develop new or modified Reliability Standards to mitigate the reliability impacts to the Bulk-Power System of such an exemption.[41]

The Commission directed NERC to develop post-disturbance ramp rate requirements as follows:

> Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop and submit to the Commission for approval new or modified Reliability Standards that require post-disturbance ramp rates for registered IBRs to be unrestricted and not programmed to artificially interfere with the resource returning to a pre-disturbance output level in a quick and stable manner after a Bulk-Power System.[42]

The Commission directed NERC to address in its IBR Ride-through standards the different types of loss synchronism as follows:

> We direct NERC to submit to the Commission for approval new or modified Reliability Standards that would require registered IBRs to ride through any conditions not addressed by the proposed new or modified Reliability Standards that address frequency or voltage ride through, including phase lock loop loss of synchronism. The

[40] *Id.* at P 193.

[41] *Id.* at P 199.

[42] *Id.* at P 208.

> proposed new or modified Reliability Standards must require registered IBRs to ride through momentary loss of synchronism during Bulk-Power System disturbances and require registered IBRs to continue to inject current into the Bulk-Power System at pre-disturbance levels during a disturbance, consistent with the IBR Interconnection Requirements Guideline and Canyon 2 Fire Event Report recommendations. Related to ACP/SEIA's comment recommending to revise the directive to require generators to maintain synchronism where possible and continue to inject current to support system stability, we direct NERC, through its standard development process, to consider whether there are conditions that may limit generators to maintain synchronism.[43]

V. NERC'S ORDER NO. 901 WORK PLAN

On January 17, 2024, NERC submitted its Informational Filing that included its Order No. 901 Work Plan.[44] NERC detailed how it will leverage the multiple standards development projects planned or already underway to address IBR-related risks and add new projects as necessary, to ensure that the reliability issues identified by the Commission in Order No. 901 are addressed appropriately through the standards development process. The Order No. 901 Work Plan consists of four key milestones with associated dates for completion, which are consistent with the Commission's direction in Order No. 901, to help ensure that the process proceeds in an orderly and timely manner. These milestones are summarized below:

- **Milestone 1:** Submission of Order No. 901 Work Plan (completed: January 17, 2024)

- **Milestone 2**: Development and Filing of Reliability Standards to Address Performance Requirements and Post-Event Performance Validation for Registered IBRs (completion: November 4, 2024)

- **Milestone 3**: Development and Filing of Reliability Standards to Address Data Sharing and Model Validation for all IBRs (completion: November 4, 2025)

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[43] *Id.* at P 209.

[44] *Informational Filing of the North American Electric Reliability Corporation Regarding the Development of Reliability Standards Responsive to Order No. 901*, Docket No. RM22-12-000 (Jan. 17, 2024) [hereinafter Order No. 901 Work Plan].

- **Milestone 4:** Development and Filing of Reliability Standards to Address Planning and Operational Studies Requirements for all IBRs (completion: November 4, 2026).

Relevant to this filing, NERC initiated the following standards project to meet the goals set in Milestone 2 of the Order 901 Work Plan:

- Project No. 2020-06, Verifications of Models and Data for Generators,
- Project No. 2021-04, Modifications to PRC-002-2 Disturbance Monitoring,
- Project No. 2020-02 Modifications to PRC-024 (Generator Ride-through), and
- Project No. 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues

The standards projects associated with Milestone 2 address IBR performance during disturbances commonly referred to as "Ride-through". These standards will focus on how to adequately monitor, analyze, report, and mitigate IBR performance during a disturbance that occurs in "ride-through" periods.

As relevant to the instant petition and discussed in detail in Section VI(H), proposed Reliability Standard PRC-029-1 addresses the Commission's Order No. 901 directives relating to IBR Ride-through performance, described in the previous section, by requiring that Generator Owners of IBRs ride through voltage and frequency excursions within the zones defined in the standard. Proposed Reliability Standard PRC-024-4 proposes to remove IBR from Reliability Standard PRC-024 to maintain capability-based requirements for synchronous generators, synchronous condensers, and asynchronous type 1 and type 2 wind generation. A summary of the Reliability Standards developed to address the Milestone 2 directives is provided below.

A. Project 2020-06 Verifications of Models and Data for Generators

Addressed in a separate filing filed concurrently with this petition, Project 2020-06 Verifications of Models and Data for Generators proposes to establish a new defined term, Inverter-Based Resource ("IBR"), for inclusion in the NERC Glossary, as follows:

> **Inverter-Based Resource (IBR)**: A plant/facility consisting of individual devices that are capable of exporting Real Power through a power electronic interface(s) such as an inverter or converter, and that are operated together as a single resource at a common point of interconnection to the electric system. Examples include, but are not limited to, plants/facilities with solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell devices.

The proposed definition of Inverter-Based Resource ("IBR") would establish a consistent understanding of the meaning of the term across all NERC Reliability Standards going forward. This term is used throughout the Order No. 901 Work Plan Milestone 2 Reliability Standards discussed below.

B. Project 2021-04 Modifications to PRC-002-2 Disturbance Monitoring

Addressed in a separate filing filed concurrently with this petition, Project 2021-04 Modifications to PRC-002-2 Disturbance Monitoring[45] proposes to establish a new Reliability Standard PRC-028-1, Disturbance Monitoring and Reporting Requirements for IBRs, to create new capability-based requirements disturbance monitoring and reporting for IBRs. The purpose of proposed Reliability Standard PRC-028-1 would be "[t]o have adequate data available from Inverter-Based Resources to evaluate Inverter-Based Resource ride-through performance during system disturbances and to provide data for Inverter-Based Resource model validation." The data collected under proposed Reliability Standard PRC-028-1 would be used to inform other Reliability Standards for Milestone 2, 3, and 4 as actual IBR performance is a core component of Order No. 901.

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[45] Project 2021-4 Modifications to PRC-002 – Phase II, https://www.nerc.com/pa/Stand/Pages/Project-2021-04-Modifications-to-PRC-002-2.aspx Project 2021-04 Modifications to PRC-002 – Phase II, https://www.nerc.com/pa/Stand/Pages/Project-2021-04-Modifications-to-PRC-002-2.aspxhttps://www.nerc.com/pa/Stand/Pages/Project-2021-04-Modifications-to-PRC-002-2.aspx.

Proposed Reliability Standard PRC-028-1, Requirement R4, provides that Generator Owners would have continuous dynamic disturbance recording data and storage to determine the electrical quantities for each main power transformer(s) it owns. This data collected under PRC-028-1 would be used to inform the analysis conducted under PRC-030-1 following an IBR performance issue. The data collected under PRC-028-1 will be essential for assessing ongoing ride-through performance for the purposes of modeling under Milestone 3. In addition, Project 2021-04 Modifications to PRC-002-2 Disturbance Monitoring proposes to remove IBR as applicable facilities from PRC-002, as the framework of that standard remains sufficient for synchronous resources.

C. Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

Project 2020-02, Modifications to PRC-024,[46] proposes to establish a new Reliability Standard PRC-029-1, Frequency and Voltage Ride-through Requirements for Inverter-based Resources, to create capability-based and performance-based requirements for IBR ride-through performance. As discussed in detail herein, Proposed Reliability Standard PRC-029-1 would "ensure that IBRs Ride-through to support the BPS during and after defined frequency and voltage excursions."

Proposed Reliability Standard PRC-029-1 would establish ride-through performance criteria and focus on the evaluation and documentation of ride-through capability. The proposed PRC-029-1 is generally an event-based standard though it is also required to provide evidence of

[46] Project 2020-02 Modifications to PRC-024 (Generator Ride-through), https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx Project 2020-02 Modifications to PRC-024 (Generator Ride-through), https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspxhttps://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx.

the capability to ride-through future grid disturbances by means such as dynamic models and simulation results.

In addition, Project 2020-02, Modifications to PRC-024, proposes to remove IBR from Reliability Standard PRC-024 to maintain capability-based requirements for synchronous generators, synchronous condensers, and asynchronous type 1 and type 2 wind generation.

D. Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues

Addressed in a separate filing filed concurrently with this petition, Project 2023-03, Analysis and Mitigation of BES Inverter-Based Resource Performance Issues,[47] proposes to establish new Reliability Standard PRC-030-1 to create new risk-based requirements for IBR Generator Owners related to IBR Performance. Proposed Reliability Standard PRC-030-1 would require Generator Owners to identify any complete facility loss of output, or changes in Real Power output that are at least 20 MW and at least 10% of the plant's gross nameplate rating, occurring within a four second period.[48] Generator Owners would then be required to analyze their IBR facility performance during the event, for the purpose of determining the root cause(s) of change(s) in Real Power output; documenting the facility's ride-through performance including Reactive Power response during the event; assessing any performance issues identified and if corrective actions are needed; and determining the applicability of the root cause(s) to the Generator Owner's other IBR facilities. As discussed below, the data from proposed Reliability Standard PRC-028-1

[47] Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues, https://www.nerc.com/pa/Stand/Pages/Project-2023-02-Performance-of-IBRs.aspx.

[48] Changes in Real Power for the following are excluded: changes associated with intermittent primary energy source availability, created by changes such as variation in wind speed and solar irradiance; resource dispatch, resource ramping, planned outages, or planned resource testing; a Transmission or collection system loss that, by configuration, disconnects the Inverter-Based Resource generator; or Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.

and the ride-through criteria established in proposed Reliability Standard PRC-029-1 would inform the analysis of ride-through performance in PRC-030-1.

Upon request, the analysis results would be provided to the requesting associated Reliability Coordinator, Balancing Authority, or Transmission Operator. If performance issues and a need for corrective actions are identified in the analysis, the Generator Owner would develop and communicate to the associated Reliability Coordinator, Balancing Authority, and Transmission Operator either a Corrective Action Plan for the identified IBR, including other applicable facilities owned by the Generator Owner, or a technical justification that addresses why corrective actions would not be taken. The Corrective Action Plan would then be implemented with any changes communicated to the associated Reliability Coordinator.

Collectively, the proposed Reliability Standards would enhance the reliability of the BPS by addressing critical IBR reliability issues in accordance with Milestone 2 of NERC's Order No. 901 Work Plan.

VI. JUSTIFICATION FOR APPROVAL: PROPOSED RELIABILITY STANDARD PRC-029-1

Proposed Reliability Standard PRC-029-1 addresses a gap in the currently effective Reliability Standards related to IBR ride-through performance during system disturbances. BPS connected generating resources remaining connected during normal and contingency conditions is a critical component of BPS reliability. Ensuring fault ride-through capability enables dynamic Reactive Power support, frequency response, and other services. Multiple NERC disturbance reports involving IBRs have shown that the unexpected and widespread loss of generating assets poses a significant risk to BPS reliability. Proposed Reliability Standard PRC-029-1 would address this issue and advance the reliability of the BPS by establishing frequency and voltage Ride-through performance criteria for IBRs to prevent unnecessary tripping or momentary cessation of current injection.

The currently effective Reliability Standards related to disturbance monitoring and generator performance during system disturbances were developed with a focus on synchronous generation resources. This focus was appropriate as it reflected the generation mix that comprised the BPS at the time they were originally developed.[49] As the resource mix is transforming to include an increasing amount of IBRs,[50] a different approach that takes into consideration the technical and operational characteristics of IBRs is needed to ensure reliability going forward.

While IBRs can produce Real and Reactive Power like synchronous generators, IBRs do not react to disturbances on the BPS in the same way. Traditional synchronous resources that are not connected to a fault will automatically ride through[51] a disturbance because they are synchronized (i.e., connected at identical speeds) to the electric power system and physically linked to support the system voltage or frequency during voltage or frequency fluctuations by continuing to produce Real and Reactive Power due to their inherent inertia.

In contrast, IBRs are not directly synchronized to the electric power system and must be programmed to support the electric power system and to ride-through a disturbance. The operational characteristics of IBRs coupled with their equipment settings may cause them to reduce

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49 PRC-024-3 and PRC-002 are the standards for ride-through and disturbance monitoring, respectively.

50 *See e.g., 2020 Long Term Reliability Assessment Report* at 9 (Dec. 2020), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf (2020 LTRA Report); *2021 Long Term Reliability Assessment Report* at 29 (Dec. 2021). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf. (NERC projects IBR nameplate capacity additions of approximately 504 GW of solar and 360 GW of wind (i.e., a total nameplate capacity of 864 GW) and cumulative retirements of approximately 60 GW of nuclear, coal, natural gas, and biomass to the Bulk-Power System over the next decade.)

51 *See Standardization of Generator Interconnection Agreements & Procs.*, Order No. 2003, 104 FERC ¶ 61,103, at P 562 n.88, (2003). (defining ride through as "a Generating Facility staying connected to and synchronized with the Transmission System during system disturbances within a range of over- and under-frequency[/voltage] conditions, in accordance with Good Utility Practice.").

power output, whether by tripping offline[52] or ceasing to inject current without tripping offline (known as momentary cessation),[53] individually or in the aggregate in response to a single fault on a transmission or sub-transmission system. Thus, the impact of IBRs is not restricted by the size of a single facility or an individual balancing authority area, but by the number of IBRs or percent of generation made up by IBRs within an interconnection. This is of particular concern because currently many simulations inaccurately predict that IBRs will maintain Real Power output and provide voltage and frequency support consistent with the purpose of Reliability Standard PRC-024-3.

Unless IBRs are configured and programmed to ride-through normally cleared transmission faults, the potential impact of losing IBRs individually or in the aggregate will continue to increase as IBRs are added to the BPS and make up an increasing proportion of the resource mix. As evaluated in past NERC reports and white papers, a controller and protection setting standard has been insufficient at ensuring actual IBR performance during voltage and frequency disturbances, contributing to a growing reliability issue.

For these reasons, the Project 2020-02 drafting team determined that Ride-through performance requirements for IBRs should be addressed by a separate standard from synchronous resources that account for the characteristics of IBRs, including their risks, performance, and equipment capabilities, as demonstrated in several recent events exhibiting significant IBR ride-

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[52] Tripping offline is a mode of operation during which part of or the entire IBR disconnects from the Bulk-Power System and therefore cannot supply Real and Reactive Power.

[53] NERC, *Reliability Guideline BPS-Connected Inverter-Based Resource Performance* at p. 11 (Sept. 2018) (IBR Performance Guideline) (Momentary cessation is a mode of operation during which the inverter remains electrically connected to the Bulk-Power System, but the inverter does not inject current during low or high voltage conditions outside the continuous operating range. As a result, there is no current injection from the inverter and therefore no active or reactive current (and no active or reactive power)) https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Inverter-Based_Resource_Performance_Guideline.pdf.

through deficiencies.[54] As result, the drafting team developed a new standard, PRC-029-1, to address the Ride-through performance of IBRs, and that PRC-024-4 would be revised to only be applicable to synchronous generators, type 1 and 2 wind plants, and synchronous condensers.

Proposed Reliability Standard PRC-029-1 addresses the reliability issues identified in multiple NERC events reports and Order No. 901 by preventing unnecessary tripping or momentary cessation of current due to phase lock loop loss of synchronism or other causes and ensuring post-disturbance ramp rates return to pre-disturbance levels. Where the need for an exemption exists, due to hardware limitations on legacy equipment, proposed Reliability Standard PRC-029-1 ensures that it is documented, communicated to all relevant entities, accepted by the Compliance Enforcement Authority, and that the entity operates to whatever its capability is to mitigate potential reliability impacts. In so doing, proposed Reliability Standard PRC-029-1 addresses the Commission's directives to address IBR ride-through issues in Order No. 901.

NERC developed the proposed Reliability Standard using NERC's standards development process. This process included multiple public comment and ballot periods. Notably, the NERC Board of Trustees initiated the use of Section 321 of the NERC Rules of Procedure at its August 15, 2024 meeting for this project in order to meet the Commission's timeline set forth in Order No. 901 directives. Section 321 allows the NERC Board of Trustees to take special actions when a ballot pool has failed to approve a proposed Reliability Standard that contains a provision to adequately address a specific matter identified in a directive. Under this special authority, the NERC Board of Trustees directed the NERC Standards Committee to work with NERC Staff to convene a technical conference to gather input from industry to address the outstanding issues and revise PRC-029-1. The technical conference took place on September 4-5, 2024, and it focused on

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[54] Event Reports *supra* note 9.

unresolved issues raised by stakeholders during the PRC-029-1 comment periods. Proposed Reliability Standard PRC-029-1 was revised based on the input from the technical conference and received the required weighted segment approval of the ballot body during its last ballot period from September 24 through October 4, 2024. The NERC Board of Trustees adopted the proposed Reliability Standards on October 8, 2024. A full summary of development is included in Exhibit G.

In this section, NERC provides an overview of the proposed Reliability Standard, with a summary of the supporting rationale, and demonstrates how proposed Reliability Standard PRC-029-1 is consistent with and addresses the directives in paragraphs 190, 193, 199, 208 and 209 of Order No. 901, listed above in Section IV(C)(1).

Additional information may be found in the Consideration of Directives included as Exhibit D, Summary of Issues and Alternatives Considered Memo included as Exhibit H, Technical Rationale for Proposed Reliability Standard PRC-029-1, included as Exhibit E-2 to this petition, as well as the Complete Record of Development, included as Exhibit G.

A. Proposed Definition of Ride-Through

Proposed Reliability Standard PRC-029-1 uses the term "Ride-through", which NERC proposes to include in the NERC Glossary. The proposed definition is:

> **Ride-through:** The plant/facility remains connected and continues to operate through voltage or frequency system disturbances.

Under the NERC *Standard Processes Manual*, definitions themselves may not include statements of performance requirements. The addition of the term Ride-through within the NERC Glossary would establish a consistent understanding of the meaning of the term across all NERC Reliability Standards going forward and clarify what is expected for a plant or facility to Ride-through a disturbance. The specific performance requirements and measures to demonstrate Ride-through are to be found within the Requirements and Attachments of proposed Reliability Standard PRC-029-1. This term is used in proposed Reliability Standard PRC-030-1 as well. References to "Ride-through criteria" in proposed Reliability Standard PRC-030-1 allow for those additional analytics to include further evaluations with PRC-029-1 Ride-through performance requirements as appropriate, while preventing duplication of those performance requirements in different Reliability Standards.

B. Title and Purpose

The title of proposed Reliability Standard PRC-029-1 is Frequency and Voltage Ride-through Requirements for Inverter-based Resources. The purpose of proposed Reliability Standard PRC-029-1 is: "To ensure that IBRs Ride-through to support the Bulk Power System (BPS) during and after defined frequency and voltage excursions."

C. Applicability

Proposed Reliability Standard PRC-029-1 is applicable to Generator Owners that own: (1) BES IBRs; and (2) non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

The proposed standard includes as applicable entities those Generator Owners that own IBRs meeting the Bulk Electric System definition criteria, which have traditionally been subject to registration for compliance with NERC Reliability Standards. It also includes those Generator Owners that own the non-BES IBRs that NERC will register in accordance with revisions to its

Rules of Procedure approved by the Commission in 2024.[55] As such, the applicability of proposed Reliability Standard PRC-029-1 is consistent with paragraph 190 of Order No. 901, in which the Commission directed NERC to develop Reliability Standards that require registered IBRs to ride-through frequency and voltage system disturbances, continue to inject current and perform frequency support during a BPS disturbance, and prohibit momentary cessation in the no-trip zone during disturbances, and establish IBR performance requirements, including requirements addressing frequency and voltage Ride through, post-disturbance ramp rates, phase lock loop synchronization, and other known causes of IBR tripping or momentary cessation.

D. Requirement R1

Proposed Reliability Standard PRC-029-1 Requirement R1 establishes requirements that all applicable IBRs will Ride-through grid voltage disturbances consistent with the "must Ride-through zone" and operation regions specified in Attachment 1. Proposed Requirement R1 would provide as follows:

> R1. Each Generator Owner shall ensure the design and operation is such that each IBR meets or exceeds Ride-through requirements, in accordance with the "must Ride-through[1] zone" as specified in Attachment 1, except in the following conditions: *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*
>
> - The IBR needed to electrically disconnect in order to clear a fault;
> - The voltage at the high-side of the main power transformer[2] went outside an accepted hardware limitation, in accordance with Requirement R4;

55 *See* IBR Registration Approval Order, *supra* note 38 Presently, the NERC *Glossary* defines the Generator Owner as the "Entity that owns and maintains generating Facility(ies)", with the term "Facility" defined as "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)." NERC has initiated a separate, high priority project, Project 2024-01 Rules of Procedure Definitions Alignment (Generator Owner and Generator Operator), to align the definitions of Generator Owner and Generator Operator in the *Glossary* with the recently approved versions of those terms as used in the NERC Rules of Procedure. The first phase of this project is scheduled for completion in early 2025. Additional information on this project is available at https://www.nerc.com/pa/Stand/Pages/Project-2024-01-Rules-of-Procedure-Definitions-Alignment_GO-and-GOP.aspx.

- The instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer and is initiated by a non-fault switching event on the transmission system[3]; or
- The Volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

[1] Includes no tripping associated with phase lock loop loss of synchronism.

[2] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for IBRs. In case of IBR connecting via a dedicated Voltage Source Converter High Voltage Direct Current (VSC-HVDC), the main power transformer is the main power transformer on the receiving end.

[3] Current blocking mode may be used for non-fault initiated phase jumps greater than 25 degrees in order to prevent tripping.

Under Requirement R1, Generator Owners of IBRs must be able to demonstrate Ride-through performance by not tripping or entering momentary cessation and must continue to exchange current and remain electrically connected, consistent with the magnitude and duration performance criteria in Attachment 1 of proposed PRC-029-1. Momentary cessation is when an inverter is temporarily current blocking while still remaining connected. Requirement R1 restricts momentary cessation to only two system conditions: 1) non-fault line switching caused voltage phase angle jumps in excess of 25 degrees that could result in tripping unless the inverter goes into current blocking, and 2) while voltage at the plant-system interface is less than 0.10 per unit during which time it may be difficult or impractical to maintain current exchange.

The drafting team determined that the terminology for "must Ride-through zones" and "operation regions" should be consistent with those terms as used within IEEE 2800-2022.[56] The "must Ride-through zones" are defined in terms of voltage and frequency magnitude and time duration. Usage of the term "must Ride-through zone," compared to the term "No trip zone," was

[56] IEEE, *Standard for Interconnection and Interoperability of Inverter-Based Resources (IBR) Interconnecting with Associated Transmission Electric Power Systems*(Apr. 22, 2022), https://standards.ieee.org/ieee/2800/10453/ (IEEE 2800-2022) (establishing uniform technical minimum requirements for the interconnection, capability, and performance of IBRs for reliable integration onto the Bulk-Power System).

also determined to prevent industry from inaccurately interpreting everything outside to be a "must trip zone". While tripping of IBR plants is permitted outside of the defined "must Ride-through zones," protection and controllers should be set in accordance with the actual capability of the IBR. Additionally, the drafting team determined that the voltage thresholds of each operation region should be based on measurements taken on the high-side of the main power transformer, which is also consistent with IEEE 2800-2022. BESS units also must comply with Requirement R1 in all operating modes including charging, discharging, and idle (energized, but not charging or discharging). A BESS in idle mode must be capable of responding to system voltage and frequency excursions as it does in charging or discharging modes.

These Ride-through zones were established based on the drafting team's experience with voltage and frequency excursions in planning and operating criteria disturbances, underfrequency load shedding stages, reasonable and practical limits of IBR voltage and frequency tolerances, and Reliability Standard PRC-024-3 voltage and frequency relay setting graphs. These include adequate margins against worst-case conditions that could be brought about during system disturbances. During the development of proposed Reliability Standard PRC-029-1, the drafting team proposed more stringent (i.e., more broad) criteria than those used in IEEE 2800-2022 due to the anticipated decrease in System inertia caused by the continual changing resource mix. Considering comments from industry received throughout the standard development process and discussion during the technical conference convened under Section 321 of the NERC Rules of Procedure, the frequency must Ride-through zones were changed to be more similar to IEEE 2800-2022 Ride-through zones. The frequency Ride-through zones are more robust than the currently effective in PRC-024-3 and require demonstration of performance. The proposed frequency Ride-through criteria is sufficient to address the recommendations identified in current NERC event reports and assessments.

Phase lock loop loss of synchronism poses a significant risk to reliability by causing IBRs to unexpectedly trip offline. When a grid disturbance occurs, such as a close-in fault or a relatively large switching event, the grid voltage may experience a rapid phase angle shift. In such cases, the phase angle displacement can be large enough to pose challenges for the phase lock loop to track the terminal voltage, cause control instability within the inverter, such as the inner current control loop or the DC link control loop, and even lead to tripping of the inverter due to the malfunction of the controls. Since phase angle jumps are common occurrences on the BPS, the proposed standard requires the IBR to be designed and operated to Ride-through a minimum phase angle jump of 25 electrical degrees. This is a typical value and aligns with the requirement in IEEE 2800-2022. Some IBR equipment has phase lock loop loss of synchronism protection, referring to a protective function that operates when the phase angle displacement exceeds a threshold for a predetermined period of time (on the order of a couple of milliseconds). Historically, this protection has been used by some inverter manufacturers, especially for inverters in distribution systems. For the IBR connected to the BPS, this protection function should be disabled. If it is enabled, the phase angle jump protection setting should be configured such that the IBR shall only trip to prevent equipment damage. Tripping due to phase lock loop loss of synchronism is specifically not permitted within voltage and frequency must Ride-through zones.

The proposed Reliability Standard provides for the following exceptions to Attachment 1 performance criteria: 1) an IBR needs to trip to clear a fault; 2) voltage at the high-side of the main power transformer goes outside an accepted and a documented hardware equipment limitation established in accordance with Requirement R4; 3) instantaneous positive sequence voltage phase angle jumps more than 25 electrical degrees at the high-side of the main power transformer initiated by a non-fault switching events occur on the transmission system; or 4) volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds. These exemptions are considered reasonable limits to ensure system stability during a voltage phase angle while protecting the hardware from incurring damage.

E. Requirement R2

Proposed Reliability Standard PRC-029-1 Requirement R2 establishes voltage Ride-through performance criteria during system disturbances for all applicable IBRs. Acceptable performance criteria depend on the operation region that an IBR is presently in or when in transition from one operation region to another operation region. Proposed Requirement R2 would provide as follows:

> R2. Each Generator Owner shall ensure the design and operation is such that the voltage performance for each IBR adheres to the following during a voltage excursion, unless a documented hardware limitation exists in accordance with Requirement R4. [Violation Risk Factor: High] [Time Horizon: Operations Assessment]
>
> 2.1. While the voltage at the high-side of the main power transformer remains within the continuous operation region as specified in Attachment 1, each IBR shall:
>
> 2.1.1. Continue to deliver the pre-disturbance level of Real Power or available Real Power[4], whichever is less.[5]
>
> 2.1.2. Continue to deliver Reactive Power up to its Reactive Power limit and according to its controller settings.
>
> 2.1.3. Prioritize Real Power or Reactive Power when the voltage is less than 0.95 per unit, the voltage is within the continuous operating region, and the IBR cannot deliver both Real Power and Reactive Power due to a current limit or Reactive Power limit, unless otherwise specified through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.
>
> 2.2. While voltage at the high-side of the main power transformer is within the mandatory operation region as specified in Attachment 1, each IBR shall exchange current, up to the maximum capability to provide voltage support, on

the affected phases during both symmetrical and asymmetrical voltage disturbances, either under[6]:

- Reactive Power priority by default; or
- Real Power priority if required through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.3. While voltage at the high-side of the main power transformer is within the permissive operation region, as specified in Attachment 1, each IBR may operate in current blocking mode if necessary to avoid tripping. Otherwise, each IBR shall follow the requirements for the mandatory operation region in Requirement R2.2.

2.3.1. If an IBR enters current blocking mode, it shall restart current exchange in less than or equal to five cycles of positive sequence voltage returning to a continuous operation region or mandatory operation region.

2.4. Each IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable high voltage thresholds and time durations in its response as voltage recovers from the mandatory or permissive operation regions to the continuous operation region.

2.5. Each IBR shall restore Real Power output to the pre-disturbance or available level[7] (whichever is lesser) within 1.0 second when the voltage at the high-side of the main power transformer returns from the mandatory operation region or permissive operation region (including operating in current blocking mode) to the continuous operation region, as specified in Attachment 1, unless an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires a lower post-disturbance Real Power level requirement or requires a different post-disturbance Real Power restoration time through other mechanisms.[8]

[4] “Available Real Power" refers to changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes of facility Real Power attributed to IBR tripping in whole or part.

[5] Except if this would occur during a frequency excursion. The Real Power response should recover in accordance with the primary frequency controller.

[6] In either case and if required, the magnitude of Real Power and reactive current shall be as specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

[7] “Available Real Power" refers to changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes of facility Real Power attributed to IBR tripping in whole or part.

[8] Except if this would occur during a frequency excursion. The Real Power response should recover in accordance with the primary frequency controller.

Under Requirement R2, a Generator Owner must adhere to the specific performance criteria that is needed to assure consistent IBR performance within each operation region in

Attachment 1 and when in transition between regions. A default post-disturbance ramp rate of 1.0 second is specified unless a faster or slower rate is specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator to accommodate specific system post-disturbance recovery needs. Any Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specified ramp rate becomes the standard requirement.

Requirement R2 Part 2.1 would ensure that when the voltage at the high-side of the main power transformer ("MPT") recovers to the continuous operation region from either the mandatory operation region or the permissive operation region, an IBR delivers the pre-disturbance level of Real Power or available Real Power, whichever is less. "Available Real Power" allows for changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes attributed to IBR tripping in whole or part. This requires an IBR to exit the "High Voltage Ride Through ("HVRT")" or "Low Voltage Ridge Through ("LVRT")" modes properly such that it does not cause reduction in the Real Power when the high-side of MPT voltage recovers to within the continuous operation region. When the voltage at the high-side of the MPT is greater than 0.90 per-unit and less than 0.95 per-unit, IBRs are expected to exit the LVRT mode and come back to "normal operating mode". If an IBR has a default total current limit of 1.0 per-unit, the apparent power production of an IBR will be limited below 1.0 per-unit (e.g., the per-unit value of IBR terminal voltage). In such case, the IBR needs to configure a preference setting, either to maintain pre-disturbance Real Power or maximize the Reactive Power to further help with voltage recovery, or according to requirements specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Requirement R2 Part 2.2 would ensure that when the voltage at the high-side of the MPT is within the mandatory operation region, IBRs inject or absorb reactive current proportional to the level of terminal voltage deviations they measure. For each IBR, the Generator Owner shall follow Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specified certain magnitude of Reactive Power response to voltage changes, if available. By default, reactive current prioritization shall be configured unless Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires Real Power priority.

Requirement R2 Part 2.3 would ensure that when the voltage at the high-side of the MPT is within the permissive operation region, IBRs continue to Ride-through, though they are briefly allowed to enter the current block mode if necessary to avoid tripping off from the grid. In developing this provision, the drafting team took into consideration the physical operational capability of the power electronics devices under such low voltage conditions. The IBR shall restart current exchange in less than or equal to five cycles of positive sequence voltage returning to the continuous operation region or mandatory operation region. If the interconnecting entity has performance requirements that are more stringent than the standard, the Generator Owner should follow the requirements set by the interconnecting entity.

Requirement R2 Part 2.4 would ensure that, when a fault is cleared on the transmission system, the voltage regulators of connected IBRs must adjust the reactive current injection to restore the transmission system voltage to the pre-disturbance voltage as defined by the automatic voltage regulator ("AVR") setpoint. It was considered that tuning of the AVR requires a balance between multiple competing physical factors, e.g., rise time, overshoot, and transient stability. However, it is anticipated that IBR controls will be tuned to allow for a stable post-disturbance voltage recovery without causing excessive overshoot or undershoot of the setpoint. When such overshoots do occur, they must not exceed the magnitudes and durations specified in the applicable table given in Attachment 1. Furthermore, the proposed standard anticipates that control system tuning to prevent such over/under voltages will focus on the speed at which the controller responds to setpoint changes rather than on the magnitude of the reactive current response. For example, reductions in k-factor to prevent over/under voltages should only be considered as a last resort.

Requirement R2 Part 2.5 would ensure that the IBR returns to effective pre-disturbance operation unless otherwise specified or needed by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator. The voltage recovery within 1 second from a disturbance is consistent with IEEE-2800 and there was no technical basis to deviate from that time duration. Ensuring that IBRs can return to pre-disturbance operation is vital to reliability. Post-disturbance injection should be coordinated by Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator because injecting current at pre-disturbance levels during the recovery from a disturbance may overcorrect in some localized areas that is not always practical or desirable for reliability.

F. Requirement R3

Proposed Reliability Standard PRC-029-1 Requirement R3 establishes Ride-through requirements for all applicable IBRs during frequency excursion events. Proposed Requirement R3 would provide as follows:

> R3. Each Generator Owner shall ensure the design and operation is such that each IBR meets or exceeds Ride-through requirements during a frequency excursion event whereby the System frequency remains within the "must Ride-through zone" according to Attachment 2 and the absolute rate of change of frequency (RoCoF)[9] magnitude is less than or equal to 5 Hz/second, unless a documented hardware limitation exists in accordance with Requirement R4. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*
>
> [9] Rate of change of frequency (RoCoF) is calculated as the average rate of change for multiple calculated system frequencies for a time period of greater than or equal to 0.1 second. RoCoF is not calculated during the fault occurrence and clearance.

Under proposed Requirement R3, IBRs would be required to remain electrically connected and continue to exchange current during a frequency excursion event in which the frequency remains within the must Ride-through zone according to Attachment 2 and while the absolute rate of change of frequency ("RoCoF") magnitude is less than or equal to 5 Hz/second. Some IBR controllers are sensitive to RoCoF, particularly auxiliary equipment that are essential for IBR performance, during a frequency excursion event.

Under Requirement R3, IBRs would be allowed to trip for an absolute RoCoF exceeding 5Hz/sec within the must Ride-through zone of Attachment 2 to maintain the stability of the IBR or prevent equipment damage. Failure to Ride-through due to RoCoF exceeding 5Hz/sec shall only be allowed during a generator/load imbalance event that causes the frequency to deviate from nominal. Additionally, IBR frequency protection settings should only be set to protect the IBR from damage caused by operation at off-nominal frequency. The IBR Generator Owner must ensure that the IBR frequency protection does not prevent an IBR from being able to Ride-through in accordance with Requirement R3.

Analysis of the Blue Cut Fire event[57] found that a significant amount of solar PV resources incorrectly determined a frequency deviation that triggered protection systems, causing those IBR to trip. These IBR controllers were not set to calculate frequency over a window of time and averaged to verify controller measurements. Under Requirement R3, frequency must be calculated as the average rate of change over multiple calculated system frequencies for some time greater than or equal to 0.1 seconds to minimize this kind of misoperation tripping of IBRs on the RoCoF setting. The RoCoF calculation is not applicable during the occurrence and clearance of a fault (i.e., protection should not trip due to any perceived RoCoF during the entire disturbance and

57 *Supra* note 10.

recovery period), and the IBR should not trip at the onset of a fault, during a fault, or at fault clearance due to the ROCOF calculation, i.e., this controller setting should be disabled during faults. The RoCoF calculation should begin after fault clearance and is only applicable for generation/load imbalance disturbances such as a system separation, an island condition, or the loss of a large load or generator.

Requirement R3 additionally requires IBR Ride-through when the calculated RoCoF is equal to or less than 5 Hz/s. This magnitude and threshold criteria is consistent with IEEE 2800-2022 and determined to be necessary to address anticipated increases of deviations from nominal grid frequency. Nominal grid frequency reflects a balance of system generation and load. A system event that causes a generation/load imbalance will cause system frequency to deviate from nominal. The system may experience an over-frequency event (in the case of more generation than load) or an under-frequency event (in the case of less generation than load). System inertia resists deviation from nominal frequency, giving system operators additional time to rebalance generation and load. System inertia is dependent on the amount of rotating mass connected to the system (i.e., synchronous generators or motors). The larger the system inertia, the slower the system frequency will deviate from the nominal value and the lower the grid RoCoF, giving more time to try to rebalance generation and load. As the grid continues to experience a shift towards generation that does not have rotating mass, planners and operators must account for increasing system frequency deviations from nominal values.

A reduction in system inertia is an inevitable consequence of a power system transitioning toward more IBR and less synchronous generators; however, the utilization of IBR-specific control features (i.e., advanced control modes and grid forming technologies) can provide additional stability benefits to help mitigate the loss of inertia. As discussed in the previous paragraph, less system inertia means the frequency will deviate from the nominal value more quickly during a generation/load imbalance event and will expose the system to a higher RoCoF.

To avoid the risk of widespread tripping, proposed Reliability Standard PRC-029-1 Attachment 2 provides a wider frequency Ride-through band than presently exists in Reliability Standard PRC-024-3 Attachment 2. This is consistent with IEEE 2800-2022, which contains frequency Ride-through times and thresholds are more stringent (i.e. wider) than those presently in Reliability Standard PRC-024-3 and contain continuous operation ranges that exceed the frequency excursions observed during major BPS disturbances. Additionally, detailed feedback from original equipment manufacturers ("OEM") provides insight that they are already designing IBR equipment that conforms with the criteria in IEEE 2800-2022. Aligning the frequency Ride-through criteria in proposed Reliability Standard PRC-029-1 with those in IEEE 2800-2022 provides a meaningful benefit to reliability while also minimizing cost and timeline implications as OEM are already designing conforming equipment.

G. Requirement R4

Proposed Reliability Standard PRC-029-1 Requirement R4 allows for IBRs that are already existing and in operation at the time proposed PRC-029-1 goes into effect ("legacy IBRs") to obtain an exemption to the voltage and frequency Ride-through requirements if hardware replacements would be necessary to comply with Requirements R1 through Requirement R3. Proposed Requirement R4 would provide as follows:

> R4. Each Generator Owner identifying an IBR that is in-service by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1-R3, and requires an exemption from specific Ride-through criteria shall:[10] *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1. This documentation shall include:

4.1.1. Identifying information of the IBR (name and facility number);

4.1.2. Which aspects of Ride-through requirements that the IBR would be unable to meet and the capability of the hardware due to the limitation;

4.1.3. Identification of the specific piece(s) of hardware causing the limitation;

4.1.4. Technical documentation verifying the limitation is due to hardware that would need to be physically replaced to meet all Ride-through criteria, and that the limitation cannot be remedied by software updates or setting changes; and

4.1.5. Information regarding any plans to remedy the hardware limitation (such as an estimated date).

4.2. Provide a copy of the information detailed in Requirement R4.1, except for any material considered by the original equipment manufacturer to be proprietary information, to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the Compliance Enforcement Authority (CEA) no later than 12 months following the effective date of PRC-029-1.[11]

4.2.1. Provide any response for additional information requested by the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA to the requestor within 90 days of the request.

4.2.2. Provide a copy of the acceptance of a hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of receiving the acceptance. [11]

4.3. Each Generator Owner with a previously accepted limitation that replaces the hardware causing the limitation shall document and communicate such a hardware change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the hardware change.

4.3.1. When existing hardware causing the limitation is replaced, the exemption for that Ride-through criteria no longer applies.

Under Requirement R4, Generator Owners owning legacy IBRs would be allowed exemptions from the voltage or frequency Ride-through performance criteria in Requirements R1-R3 if such limitations are documented and communicated to the Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator of the respective footprints in which the IBR is located. The Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator would then need to take the voltage or frequency Ride-through limitations into account in planning and operations.

The drafting team determined that an exemption to the Ride-through performance criteria was necessary for legacy IBRs because of the hardware limitations associated with those facilities. Specifically, it was determined that the anticipated difficulty of Generator Owners having to wholesale retrofit and redesign legacy facilities currently in operation would be unreasonable and unduly burdensome, and it could lead to undesirable impacts on reliability. Entities would be required to take units offline to retrofit or risk noncompliance and could choose to retire the units instead of retrofit based on economic considerations. A proposed IBR Ride-through standard having no exemptions could result in a resource capacity deficiency due to these retired units and thus lead to a substantial negative impact to reliability of the BPS.

A Generator Owner may seek an exemption from both the voltage and frequency Ride-through criteria. In Order No. 901 the Commission only directed NERC to consider if an exemption from the voltage Ride-through criteria was necessary. After reviewing stakeholder feedback on the draft standard, the drafting team concluded that an exemption to the frequency Ride-through criteria would also be necessary and appropriate. During the technical conference convened under Section 321, the Standards Committee and NERC Staff included a panel discussion on frequency exemptions. Panelists discussed various challenges related to legacy IBR, such as difficulties obtaining more detailed information on equipment capabilities; specifically for manufacturers who are no longer in business and for IBR that are no longer supported by the manufacturer. Other concerns raised included the possibility that manufacturers would not be willing to provide design or hardware limitation documentation should they identify the information to be proprietary information.[58]

Following the technical conference, NERC staff and the Standards Committee determined that a frequency exemption to the Ride-through criteria was necessary, in addition to the voltage exemption contemplated in Order No. 901, because of hardware-based capability limitations due to manufacture design for a significant amount of installed IBRs. Without a frequency exemption, these legacy IBRs may be required to go offline to refit to comply with proposed Reliability Standard PRC-029-1. It was determined that a potential disconnection of a large amount of installed IBR capacity overwhelmingly indicated a reliability need to allow for a documented and limited set of exemptions for IBR from voltage and frequency ride-through criteria. In light of this reliability concern, Requirement R4 of proposed Reliability Standard PRC-029-1 allows for a documented, and limited, set of exemptions for IBR from frequency Ride-through criteria. This exemption process is discussed below.

Under Requirement R4 Part 4.1, the IBR Generator Owner must document the need for an exemption. The documentation must identify the hardware that prevents the IBR from meeting Ride-through criteria, describe the aspect(s) of the Ride-through criteria that cannot be met, and provide information regarding what the IBR is capable of despite the limitation. Any exemptions due to hardware limitations must not be construed as complete exemptions from the applicable Ride-through criteria in Attachment 1. Exemptions must be specific and limited to the voltage or frequency band(s) and associated duration(s) that cannot be satisfied or as to the number of cumulative voltage deviations within a ten-second time period that the equipment can Ride-

58 *See* Exhibit G Complete Record of Development at item 14, Day 2 Recording and Transcript of the Standards Committee & NERC Ride-through Technical Conference; Project 2020-02 Modifications to PRC-024 (Generator Ride-through) Related Files; posted September 18, 2024.

through if its less than four deviations within any ten-second time period. For this reason, when describing the hardware limitations, the Generator Owner must identify the specific equipment and explain the characteristic(s) of that equipment that prevent Ride-through.

Under Requirement R4 Part 4.2, this Generator Owner must submit such information to the Transmission Planner, Planning Coordinator, Reliability Coordinator, Transmission Operator, and Compliance Enforcement Authority. Further, the IBR must perform in accordance with the capability of the plant, accounting for the limitation, for those criteria identified in the documentation for exemption.

Under Requirement R4 Part 4.2.1, the Generator Owner is required to supply further information on the need for and the nature of the exemption if requested by the Transmission Planner, Planning Coordinator, Reliability Coordinator, Transmission Operator, or Compliance Enforcement Authority.

Under Requirement R4 Part 4.2.2, the Compliance Enforcement Authority must accept that all aspects of the documentation specified in proposed Requirement R4 have been provided by the Generator Owner before an exemption can granted. This would ensure that NERC has visibility into each hardware exemption that is granted and that they have been accurately limited to the particular limitation of the hardware. NERC would work with the Regional Entities to develop a framework for evaluating any exemption submissions in a fair and consistent manner across the ERO Enterprise. NERC would also monitor the use of this process and the disposition of requests as the proposed standard is implemented. To the extent NERC determines any further action would be prudent, it would be dependent on the volume and nature of the hardware limitations being submitted for Compliance Enforcement Authority acceptance. NERC will consult with Commission staff as it performs this oversight activity.

Under Requirement R4 Part 4.3, if the hardware causing the limitation is replaced and the limitation is removed, then the exemption no longer applies. The IBR Generator Owner must communicate to the Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator of the hardware and change to anticipated performance within 90 days of the hardware replacement. This is to ensure that all IBRs capable of fully complying with the Ride-through criteria in Requirements R1-R3 do so as soon as possible.

H. Consideration of FERC Order No. 901 Directives

Proposed Reliability Standard PRC-029-1 is responsive to the Commission's performance directives in paragraphs 190, 193, 199, 208 and 209 of Order No. 901, described above in Section IV(C)1. The Commission directed NERC to develop performance-based Reliability Standards that require IBRs to Ride-through system disturbances and require post-disturbance ramp rates to return to pre-disturbance levels. The Commission further directed NERC to determine if an exemption from Ride-through criteria is necessary and, if so, that it is only for a limited and documented set of existing IBRs, and that NERC develop new or modified Reliability Standards to mitigate the reliability impact of any such exemptions. The following discussion summarizes how proposed Reliability Standard PRC-029-1 addresses these directives, as further discussed in the Consideration of Directives included as Exhibit D hereto.

1. <u>Paragraph 190 Directing Reliability Standards Addressing IBR Ride-through Performance</u>

In paragraph 190 of Order No. 901, the Commission issued several directives for NERC related to Reliability Standards for IBRs to Ride-though system disturbances. Each of these are addressed in turn below.

First, the Commission directed NERC to require that registered IBRs "ride through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults."[59] To address the reliability concerns for the voltage component of this directive, proposed Reliability Standard PRC-029-1 Requirement R1 would require registered Generator Owners of IBRs to both design and operate their IBR plants to Ride-through voltage excursions within "must Ride-through zones" according to how these zones are defined in the standard. Proposed Reliability Standard PRC-029-1 Requirement R3 would require the same design and operation Ride-through requirements for Ride-through frequency excursions. The must Ride-through zones used within the requirements and Attachments are defined in terms of voltage and frequency magnitudes and time durations. Tripping of IBR plants is permitted only outside of the defined must Ride-through zones.

Second, in paragraph 190, the Commission directed NERC to require that registered IBRs "continue to inject current and perform frequency support during a Bulk-Power System disturbance."[60] NERC addresses this directive in proposed Reliability Standard PRC-029-1 Requirements R1-R3. These requirements would require IBRs to Ride-through system disturbances. The proposed Ride-through definition states that IBR facilities must remain connected and continue to fulfill their established control and regulation functions (which generally involve exchange of current) to qualify as riding through system disturbances. Support of frequency is predicated on, and to a large degree achieved by being able to Ride-through system disturbances.

Third, in paragraph 190, the Commission directed NERC to develop requirements that "prohibit momentary cessation in the no-trip zone during disturbances."[61] Proposed Reliability

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59 Order No. 901 P 190.

60 *Id.*

61 *Id.*

Standard PRC-029-1 addresses this directive in Requirement R1, which would require IBRs to meet or exceed Ride-through requirements in Attachment 1. As discussed above, these Ride-through requirements would restrict the use of momentary cessation to the following two system conditions: 1) non-fault line switching caused voltage phase angle jumps in excess of 25 degrees that could result in tripping unless the inverter goes into current blocking; and 2) voltage at the plant-system interface that is less than 0.10 per unit during which time it may be difficult or impractical to maintain current exchange.

Lastly, in paragraph 190, the Commission directed NERC to require that registered IBRs have "performance requirements, including requirements addressing frequency and voltage Ride-through, post-disturbance ramp rates, phase lock loop synchronization, and other known causes of IBR tripping or momentary cessation."[62] Proposed Reliability Standard PRC-029-1 addresses this directive in Requirement R1. As noted above, Requirement R1 establishes IBR frequency and voltage Ride-through requirements. The proposed requirement also specifies a default post-disturbance ramp rate of 1.0 second unless a faster or slower rate is specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator to accommodate specific system post-disturbance recovery needs. Additionally, tripping due to phase lock loop loss of synchronism is specifically not permitted within voltage and frequency must Ride-through zones.

2. Paragraph 193: Consideration of Voltage Ride-Through Performance Exemptions

In paragraphs 193 and 199 of Order No. 901, the Commission directed NERC to consider whether the proposed new or revised Reliability Standard should contain exemptions to the Ride-

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[62] *Id.*

through performance requirements for those legacy IBRs that are currently in operation and unable to meet the requirements.

First, in paragraph 193 of Order No. 901, the Commission directed NERC to "determine whether the new or modified Reliability Standards should provide for a limited and documented exemption for certain registered IBRs from voltage Ride-through performance requirements."[63] As discussed more fully above, NERC has determined that a limited and documented exemption for certain registered IBRs from voltage or frequency Ride-through performance requirements would be appropriate. Thus, proposed Reliability Standard PRC-029-1 Requirement R4 establishes a process by which entities may obtain an exemption from the voltage or frequency Ride-through criteria of PRC-029-1 Requirement R1 or Requirement R3 for IBR plants/facilities that are in service at the effective date of the standard. Although Order No. 901 was silent regarding the need for NERC to consider frequency Ride-through exemptions, NERC determined that frequency exemptions were needed to address significant OEM design capability limits regarding frequency thresholds. More information on why a frequency exemption was determined to be necessary can be found in the discussion of Requirement R4, above, and in the Summary of Issues and Alternatives Considered Memo included as Exhibit H.

In all cases, the IBR Generator Owner must document the need for an exemption, and the documentation must explain what hardware prevents the IBR from meeting Ride-through criteria, which aspect(s) of the Ride-through criteria that cannot be met, and information regarding what the IBR is capable of despite the limitation. The Generator Owner must then submit this information to the Transmission Planner, Planning Coordinator, Reliability Coordinator, Transmission Operator, and Compliance Enforcement Authority. Further, the IBR must perform

63 *Id.* at P 193.

in accordance with the capability of the plant, accounting for the limitation, for those criteria identified in the documentation for exemption. The Compliance Enforcement Authority checks that all aspects of the documentation specified in Requirement R4 have been provided by the Generator Owner, and the Generator Owner is required to supply further information on the need for and the nature of the exemption if requested by the Transmission Planner, Planning Coordinator, Reliability Coordinator, Transmission Operator, or Compliance Enforcement Authority. The implementation plan provides a 12-month time window for exemption requests to be submitted following the enforcement date. Following the 12-month window, further exemption requests will not be accepted or could be considered an admission of non-compliance.

Second, in paragraph 193 the Commission directs NERC "to ensure that any such exemption would be applicable for only existing equipment that is unable to meet voltage Ride-through performance. When such existing equipment is replaced, the exemption would no longer apply, and the new equipment must comply with the appropriate IBR performance requirements…"[64] The exemption provision in Requirement R4 addresses this directive by providing that exemptions are available only for IBR plants/facilities that are in service at the effective date as noted above. The exemption provision also stipulates that once the plant/facility hardware causing the limitation is replaced, the exemption no longer applies.

Lastly, in paragraph 193 the Commission directed NERC "to require the limited and documented exemption list (i.e., IBR generator owner and operator exemptions) to be communicated with their respective Bulk-Power System planners and operators."[65] The exemption provision in Requirement R4 addresses this directive as it requires an IBR Generator Owner to

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64 *Id.*

65 *Id.*

supply its exemption request documentation to its Transmission Planner, Planning Coordinator, Reliability Coordinator, and Transmission Operator within the 12-month window following the effective date as noted above.

3. Paragraph 199: Mitigation of Reliability Impacts from Ride-through Exemptions

In paragraph 199 of Order No. 901, the Commission directed NERC to mitigate the reliability impacts to the Bulk-Power System of any exemptions from Ride-through requirements.[66] The reliability impacts of voltage or frequency must Ride-through exemptions are mitigated by existing NERC Reliability Standards addressing the responsibilities of Transmission Planners, Planning Coordinators, Reliability Coordinators, and Transmission Operators.[67] These entities routinely conduct evaluations of potential impacts to the grid for a variety of different operating conditions, scenarios, and time windows. These entities have the obligation to require Corrective Action Plans be developed in accordance with the requirements of those other standards when such adverse system conditions exceeding acceptable thresholds are identified in the studies required by those other standards. Additionally, under Milestone 4 of the Order No. 901 Work Plan, NERC will develop Reliability Standards that will specifically require evaluations that include accurately-modeled performance capabilities of IBR, inclusive of any documented Ride-through criteria exemption accepted through the process detailed in proposed Reliability PRC-029-1 Requirement R4, and that evaluate for reliability impacts on the BPS.

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[66] *Id.* at P 199.

[67] *See e.g.* Reliability Standards; IRO-002-7 - Reliability Coordination - Monitoring and Analysis; IRO-008-3 – Reliability Coordinator Operational Analyses and Real-time Assessments; TOP-002-4 — Operations Planning; TPL-001-5.1 — Transmission System Planning Performance Requirements

4. Paragraph 208: Post-Disturbance Ramp Rates Return to Pre-Disturbance Output

In paragraph 208 of Order No. 901, the Commission directed NERC to "develop and submit to the Commission for approval new or modified Reliability Standards that require post-disturbance ramp rates for registered IBRs to be unrestricted and not programmed to artificially interfere with the resource returning to a pre-disturbance output level in a quick and stable manner after a Bulk-Power System disturbance event."[68] Proposed Reliability Standard PRC-029-1 addresses this directive in Requirement R2. As noted above, Requirement R2 is responsive to this directive because it has a default post-disturbance ramp rate of 1.0 second specified unless a faster or slower rate is specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator to accommodate specific system post-disturbance recovery needs. Any Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specified ramp rate criteria becomes the standard required criteria for this aspect of Ride-through performance.

5. Paragraph 209: Ride-Through Standards Must Address Different Types of Loss of Synchronism

Paragraph 209 of Order No. 901 contains several directives for NERC regarding IBRs ability to Ride-Through different types of loss of synchronism. Each of these are addressed in turn.

First, the Commission directed NERC to require that registered IBRs "ride through any conditions not addressed by the proposed new or modified Reliability Standards that address frequency or voltage ride through, including phase lock loop loss of synchronism."[69] Proposed Reliability Standard PRC-029-1 addresses this directive in Requirement R1. As noted above, under Requirement R1, phase lock loop loss of synchronism is not allowed as a cause of tripping while

[68] Order No. 901 at P 208.

[69] *Id*. at P 209.

voltage remains within the must Ride-through zone unless there are phase jumps more than 25 degrees caused by non-fault switching events. A footnote under Requirement R1 also specifically states that phase lock loop loss of synchronism as not a permissible condition for tripping while voltage remains within the must Ride-through zone.

Second, the Commission directed NERC to require that registered IBRs "ride through momentary loss of synchronism during Bulk-Power System disturbances and require registered IBRs to continue to inject current into the Bulk Power System at pre-disturbance levels during a disturbance, consistent with the IBR Interconnection Requirements Guideline and Canyon 2 Fire Event Report recommendations."[70] Proposed Reliability Standard PRC-029-1 addresses this directive in Requirements R1 and R2. As noted above, Requirement R1 specifically does not permit tripping due to phase lock loop loss of synchronism within voltage and frequency must Ride-through zones. Requirement R2 specifies that IBRs are required to have Real and Reactive Power performance during voltage disturbances. Additionally, Requirement R2 requires IBRs to return to pre-disturbance power injection. Requirement R2 Part R2.1.1 includes a provision to return to "Available Active Power" to allow for "changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance." However, "changes of facility Real Power attributed to IBR tripping in whole or part" are not permitted under Requirement R2 Part R2.1.1. The reason for this is to ensure clarity regarding allowable changes due to changes in the IBR fuel source rather than due to any tripping of the IBR, in whole or in part.

[70] *Id.*

Lastly, the Commission directed NERC "to consider whether there are conditions that may limit generators to maintain synchronism."[71] NERC determined that IBRs are non-synchronous but can exhibit forms of instability other than loss of synchronism. System stability is a shared responsibility of Transmission Planners, Planning Coordinators, Reliability Coordinators, and Transmission Operators. IBR generation levels may need to be restricted by these entities to maintain System stability or to mitigate known System constraints to a localized area.

VII. JUSTIFICATION FOR APPROVAL: PROPOSED RELIABILITY STANDARD PRC-024-4

Proposed Reliability Standard PRC-024-4 contains revisions that would enable the standard to be retained as a protection-based standard with applicability to only synchronous generators, synchronous condensers, and type 1 and type 2 wind units. Proposed Reliability Standard PRC-024-4 would continue to address frequency and voltage protection setting ranges for synchronous units as they do not require performance-based requirements to Ride-through disturbances. Additionally, consistent with the proposed definition of IBR developed under Project 2020-06, type 1 and 2 wind units are not considered IBRs. These wind turbine types operate as asynchronous generating resources and do not have modern controllers capable of riding through system events.

The revised standard applicability of proposed Reliability Standard PRC-024-4 is supported by the different natures of synchronous and IBR generation resources, including their risks, performance, and equipment capabilities. As described above, NERC's Project 2020-02, Modifications to PRC-024, was initiated by NERC in response to several event reports where widespread loss of IBRs abnormally tripped, ceased current injection, or reduced power output

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71 *Id.*

with control interactions. For the reasons described below, there is no need to impose actual disturbance Ride-through requirements on synchronous units but only to include restrictions for frequency and voltage protection setting ranges as maintained in PRC-024-4.

The behavior of rotating synchronous generators during faults and other disturbances on the transmission system is well established and understood in comparison to IBR generation. The disturbance Ride-through vulnerabilities of synchronous generators are pole slipping instability and undervoltage dropout of critical plant auxiliary equipment, leading to tripping of a generator. NERC determined that these issues did not need to be addressed in Project 2020-02, as pole slipping (or loss of synchronism) can be managed by Real Power dispatch constraints or stability System Operating Limits. Auxiliary equipment has not posed a Ride-through risk.

Over-frequency protection, under-frequency protection, over-voltage protection, and under-voltage protection may or may not be applied to synchronous generating units. If applied, settings should be coordinated between the needs of generating unit protection and the no-trip zones within PRC-024-4 attachments. Coordination of generating unit capabilities, voltage regulating controls, and protection is addressed within Reliability Standard PRC-019-2. Excitation and governing controls affect synchronous generator Ride-through behavior to some degree but because of progressive improvement, standardization, and level of maturity of these controls, they are rarely a cause of unnecessary tripping during disturbances. In addition, there are other existing NERC standards to prevent unnecessary tripping of the generators during a system disturbance such as PRC-025-2 - Generator Relay Loadability and PRC-026-2 - Relay Performance During Stable Power Swings.

NERC developed the proposed Reliability Standard using NERC's standards development process. This process included multiple public comment and ballot periods. The NERC Board of Trustees adopted proposed Reliability Standard PRC-024-4 on October 8, 2024.

In this section, NERC provides an overview of the proposed Reliability Standard, with a summary of the supporting rationale. Additional information may be found in the Technical Rationale for Proposed Reliability Standard PRC-024-4, included as Exhibit E-1 to this petition, as well as the Complete Record of Development, included as Exhibit G.

A. Title and Purpose

The title of proposed Reliability Standard PRC-024-4 is – Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and 2 Wind Plants, and Synchronous Condensers. The purpose is to ensure that protection of synchronous generators, type 1 and type 2 wind resources, and synchronous condensers do not cause tripping during defined frequency and voltage excursions in support of the BPS.

B. Applicability

Proposed Reliability Standard PRC-024-4 is still applicable to Generator Owners and Transmission Owners, as well as Planning Coordinators which are applicable entities only in the Quebec Interconnection. The functional entity responsible for setting frequency, voltage, and volts per hertz protection for synchronous generators, type 1 and 2 wind plants, and synchronous condensers is either the Generator Owner or Transmission Owner. Modifications are proposed in PRC-024-4 to expand functional entity applicability to include "Transmission Owners that apply protection" because of the inclusion of synchronous condenser applicability in section 4.2.2.

The Applicable Facilities in subparts in Section 4.1.1 were modified to restrict PRC-024-4 to synchronous generators and type 1 and 2 wind plants. Section 4.2.2 was added to include synchronous condensers and associated equipment.

C. Requirements

Proposed Reliability Standard PRC-024-4 modifies Requirements R1, R2, R3, and R4 to include the Transmission Owner as a functional entity applicable to each requirement due to the addition of synchronous condensers in the applicable facilities. Additionally, modifications were made to Requirements R1, R2, R3, and R4 to include language that relates to type 1 and 2 wind plants and synchronous condensers and to remove language that relates to IBR functionality since IBRs are addressed in proposed Reliability Standard PRC-029-1.

VIII. ENFORCEABILITY OF PROPOSED RELIABILITY STANDARDS

The proposed Reliability Standards include measures that support each requirement by clearly identifying what is required and how the ERO will enforce the requirement. These measures help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[72] Additionally, the proposed Reliability Standards include VRFs and VSLs. The VRFs and VSLs provide guidance on the way that NERC will enforce the requirements of the proposed Reliability Standards. The VRFs and VSLs for the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment. Exhibit F provides a detailed review of the VRFs and VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines.

IX. EFFECTIVE DATE OF THE PROPOSED RELIABILITY STANDARDS

NERC respectfully requests that the Commission approve the proposed Reliability Standards to become effective as set forth in the proposed Implementation Plan, provided in Exhibit B hereto. The proposed Implementation Plan provides that the proposed Reliability Standards PRC-024-4 and PRC-029-1 shall become effective on the first day of the first calendar

[72] Order No. 672 at P 327.

quarter that is twelve calendar months after the effective date of the Commission's order approving the proposed Reliability Standard. Currently effective Reliability Standard PRC-024-3 would be retired immediately prior to the effective date of proposed Reliability Standard PRC-024-4. The Implementation Plan for proposed PRC-029-1 provides phased-in compliance dates for both capability and performance-based elements of Requirements R1, R2, and R3 for BES IBRs and non-BES IBRs.

For BES IBRs, the implementation timeframe for capability-based elements is as follows. Generator Owners shall comply with the portion of Requirements R1, R2, and R3 relating to the design of their BES IBRs to meet the requirements by the effective date of the standard. Additionally, the implementation timeframe for the exemption process in Requirement R4 is the effective date of the standard.

For non-BES IBRs, the implementation timeframe for capability-based elements is as follows. Generator Owners shall comply with the portion of Requirements R1, R2, and R3 relating to the design of their applicable non-BES IBRs until the later of: (1) January 1, 2027; or (2) the effective date of the standard. Additionally, the implementation timeframe for the exemption process in Requirement R4 is the later of: (1) January 1, 2027; or (2) the effective date of the standard.

For all IBRs, the implementation timeframe performance-based elements is as follows. Generator Owners shall not be required to comply with the portion of Requirements R1, R2, and R3 relating to the operation of IBRs to meet the requirements until the entity has established the required disturbance monitoring equipment capabilities for those IBRs in accordance with the implementation plan for proposed Reliability Standard PRC-028-1.[73] Under that plan, Generator Owners will follow a phased-in compliance timeline with requirements to establish disturbance monitoring capabilities fully implemented by January 1, 2030.

This Implementation Plan recognizes the need for this phased in compliance timeline so entities can establish disturbance monitoring capabilities before having to comply with the performance-based elements of proposed Reliability Standard PRC-029-1. Further, Generator Owners and Generator Operators owning or operating BPS connected IBRs that do not meet NERC's current definition of BES will be registered no later than May 2026 in accordance with the IBR Registration proceeding in FERC Docket No. RR24-2. To ensure an orderly registration and compliance process for these entities, as well as fairness and consistency in the standard's application among similar asset types, the proposed Implementation Plan provides additional time for both new and existing registered entities to come into compliance with new IBR Ride-through requirements for their applicable IBRs not meeting the BES definition. In so doing, this Implementation Plan advances an orderly process for new registrants while allowing existing

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[73] The proposed implementation plan for proposed Reliability Standards PRC-028-1 and PRC-002-5 provides that the proposed standards would become effective the first calendar quarter following regulatory approval. Implementation of PRC-028-1 would then follow a phased-in compliance timeline, ending by 2030. The relevant dates under that plan are as follows:

BES IBRs: Generator Owners shall comply with requirements to establish disturbance monitoring data recording capabilities for 50% of their existing BES IBRs (i.e. in commercial operation on or before the effective date) within three calendar years of the effective date of PRC-029-1, and 100% of their BES IBRs by January 1, 2030. If a Generator Owner has only one such BES IBR, it shall comply within three calendar years. For new BES IBRs, Generator Owners shall comply within 15 calendar months following the effective date of the standard or by the commercial operation date, whichever is later.

Non-BES IBRs: Generator Owners shall comply with requirements to establish disturbance monitoring data recording capabilities for 100% of those non-BES IBRs in commercial operation prior to May 15, 2026 by no later than January 1, 2030. Generator Owners shall comply with for their new non-BES IBRs within 15 calendar months following the effective date of the standard or by the commercial operation date, whichever is later.

Additional information is available in Section VIII and Exhibit B to NERC's Petition for Approval of Proposed Disturbance Monitoring Reliability Standards PRC-028-1 and PRC-002-5 (Nov. 4, 2024).

entities to focus their immediate efforts on their assets posing the highest risk to the reliable operation of the BPS.

Consistent with Order No. 672, the proposed implementation plan balances the urgency in the need to implement new requirements for IBR Ride-through performance, a need which is demonstrated in multiple NERC event reports and highlighted in Order No. 901, while providing a reasonable amount of time for those who must comply to develop the necessary procedures, software, facilities, staffing, or other relevant capability.[74] The proposed implementation plan is also consistent with the Commission's directive in Order No. 901 that "there is a need to have all of the directed Reliability Standards effective and enforceable well in advance of 2030 and direct NERC to ensure that the associated implementation plans sequentially stagger the effective and enforceable dates to ensure an orderly industry transition for complying with the IBR directives in this final rule prior to that date."[75]

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74 Order No. 672 at P 333.

75 Order No. 901 at P 226.

X. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve:

- proposed Reliability Standards PRC-024-4 and PRC-029-1, and associated elements included in Exhibit A, effective as proposed herein;
- the proposed Implementation Plan included in Exhibit B; and
- the retirement of Reliability Standard PRC-024-3 effective as proposed herein.

Respectfully submitted,

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Date: November 4, 2024

Exhibit A

Proposed Reliability Standards

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-1

PRC-024-4 Clean

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

Draft 3 of PRC-024-4 is posted for final ballot. Non-substantive corrections were identified during the last additional ballot. This draft includes those corrections.

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023
25-day formal comment period with initial ballot	March 27 - April 22, 2024
15-day formal comment period and additional ballot	June 18 – July 8, 2024

Anticipated Actions	Date
Final ballot	September 25 – September 30, 2024
Board Adoption	October 8, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

A. Introduction

1. **Title:** **Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and Type 2 Wind Resources, and Synchronous Condensers**

2. **Number:** **PRC-024-4**

3. **Purpose:** To assure that protection of synchronous generators, type 1 and type 2 wind resources, and synchronous condensers do not cause tripping during defined frequency and voltage excursions in support of the Bulk Power System (BPS).

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Generator Owners that apply protection listed in Sections 4.2.1 or 4.2.2.

4.1.2. Transmission Owners that apply protection listed in Section 4.2.2.

4.1.3. 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.

4.1.4. 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 trip; and are applied to the following:

4.2.1.1 Bulk Electric System (BES) synchronous generators.

4.2.1.2 BES GSU transformer(s) for synchronous generators.

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

4.2.1.4 Individual dispersed power producing type 1 or type 2 wind resource(s) identified in the BES Definition, Inclusion I4.

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[1] For the purpose of this standard, the MPT is the power transformer that steps up voltage from multiple small synchronous generators (e.g. multiple small hydro generators connecting to a common bus) or from a type 1 or type 2 wind resource collector station to transmission voltage .

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

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

4.2.1.5 Elements that are designed primarily for the delivery of capacity from multiple synchronous generators connecting to a common bus or individual dispersed power producing type 1 or type 2 wind resources identified in the BES Definition, Inclusion I4, to the point where those resources aggregate to greater than 75 MVA.

4.2.1.6 MPT of multiple synchronous generators connecting to a common bus or MPT of individual dispersed power producing type 1 or type 2 wind resources as identified in the BES Definition, Inclusion I4.

4.2.2 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 transmission connected synchronous condensers; or (ii) provide signals to trip transmission connected synchronous condenser and are applied to the following:

4.2.2.1 BES synchronous condensers

4.2.2.2 BES step-up transformer(s) for synchronous condensers.

4.2.2.3 High-side of the synchronous condenser-connected unit auxiliary transformer (UAT).

4.2.3 **Exemptions:** Protection on all auxiliary equipment within the synchronous generator, type 1 or type 2 wind resource, or synchronous condenser Facility.

5. **Effective Date:** See Implementation Plan for PRC-024-4

B. Requirements and Measures

R1. Each Generator Owner and Transmission Owner shall set applicable frequency protection[4] in accordance with PRC-024-4 Attachment 1 such that the applicable protection does not cause the Facility to which it is applied to trip within the "no trip zone" during a frequency excursion with the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Applicable frequency protection may be set to trip within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M1. Each Generator Owner and Transmission Owner shall have evidence that the applicable frequency protection has been set in accordance with Requirement R1, such as dated setting sheets, calibration sheets, calculations, or other documentation.

R2. Each Generator Owner and Transmission Owner shall set applicable voltage protection[5] in accordance with PRC-024-4 Attachment 2, such that the applicable protection does not cause the Facility to which it is applied to trip within the "no trip zone" during a voltage excursion at the high-side of the GSU or MPT, 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-024-4 Attachment 2, then the Generator Owner or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- Applicable voltage protection may be set to trip during a voltage excursion within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M2. 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.

R3. Each Generator Owner and Transmission Owner shall document each known regulatory or equipment limitation[6] that prevents its Facility, with applicable frequency or voltage protection from meeting the 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]*

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[4] 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 synchronous generator(s), type 1 or type 2 wind resource(s), or synchronous condenser(s); or (ii) provide signals to trip the same Facilities.
[5] Ibid.
[6] Excludes limitations caused by the setting capability of the frequency, voltage, and volts per hertz protective relays applied to the synchronous generator(s), type 1 and type 2 wind resource(s), and synchronous condenser(s). This does not exclude limitations originating in the equipment protected by the relay(s).

3.1. The Generator Owner and Transmission 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 and Transmission Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations 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.

R4. Each Generator Owner and Transmission Owner shall provide its applicable protection settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated Facility 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 settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of protection setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Generator Owner and Transmission Owner shall have evidence that it communicated applicable protection settings in accordance with Requirement R4, such as dated emails, correspondence or other evidence and copies of any requests it has received for that information.

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.

1.2. Evidence Retention: 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 and Transmission Owner shall keep data or evidence of Requirements R1 through R4 for five years or until the next audit, whichever is longer.
- If a Generator Owner or Transmission 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.

1.3. Compliance Monitoring and Enforcement 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.

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 or Transmission Owner failed to set its applicable frequency protection so that it does not trip according to Requirement R1.
R2.	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 according to Requirement R2.
R3.	The Generator Owner or Transmission 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 or Transmission 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 or Transmission 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 or Transmission 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 or Transmission Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				days of identifying the limitation.
R4.	The Generator Owner or Transmission Owner provided its protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner or provided protection settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner or Transmission Owner failed to provide its protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner failed to provide protection settings within 150 calendar days of a written request.

D. Regional Variances

D.A. Variance for the Quebec Interconnection

This Variance 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.

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

D.A.2. Each Generator Owner and Transmission Owner shall set applicable voltage protection[7] in accordance with PRC-024 Attachment 2A, such that the applicable protection does not cause the Facility to which it is applied to trip within the "no trip zone" during a voltage excursion 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".
- Applicable voltage protection may be set to trip during a voltage excursion within a portion of 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.

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,

[7] 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 synchronous generator(s), type 1 or type 2 wind resource(s), or synchronous condenser(s); or (ii) provide signals to trip the same Facilities.

each Generator Owner or Transmission Owner that owns facilities[8] 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.

[8] Facilities in the strategic power plants include facilities with synchronous generator(s) 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 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 facilities in the strategic power plants between 31 days and 45 days after its designation.	The Planning Coordinator designated strategic power plants at least once every five calendar years but notified each Generator Owner or Transmission Owner that owns facilities in the strategic power plants between 46 days and 60 days after its designation.	The Planning Coordinator failed to designate, at least once every five years, the strategic power plants that must comply with Attachment 2A. 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 its designation.

E. Associated Documents

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	February 6, 2020	Adopted by the NERC Board of Trustees	Standard revised in Project 2018-04
3	July 9, 2020	FERC Letter Order approved PRC024-3. Docket No. RD20-7-000	
3	July 17, 2020	Effective Date	10/1/2022
4	August 2, 2024	Revisions made by the 2020-02 Drafting Team	Revision accounts for changes with PRC-029-1 as part of Milestone 2 of NERC's work plan to address FERC Order No. 901.

Attachment 1
(Frequency No Trip Boundaries by Interconnection[9])

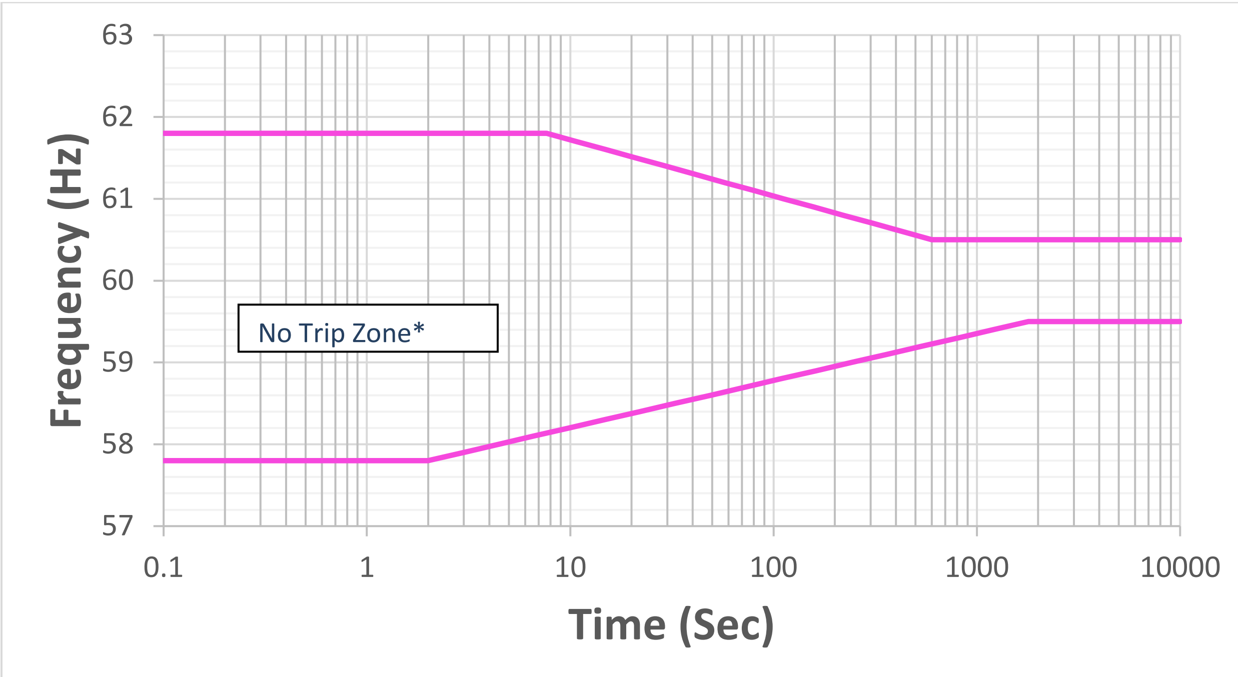

Figure 1: Eastern Interconnection Boundaries

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

Table 1: 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[10]	≤57.8	Instantaneous[11]
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

[9] 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.
[10] 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.

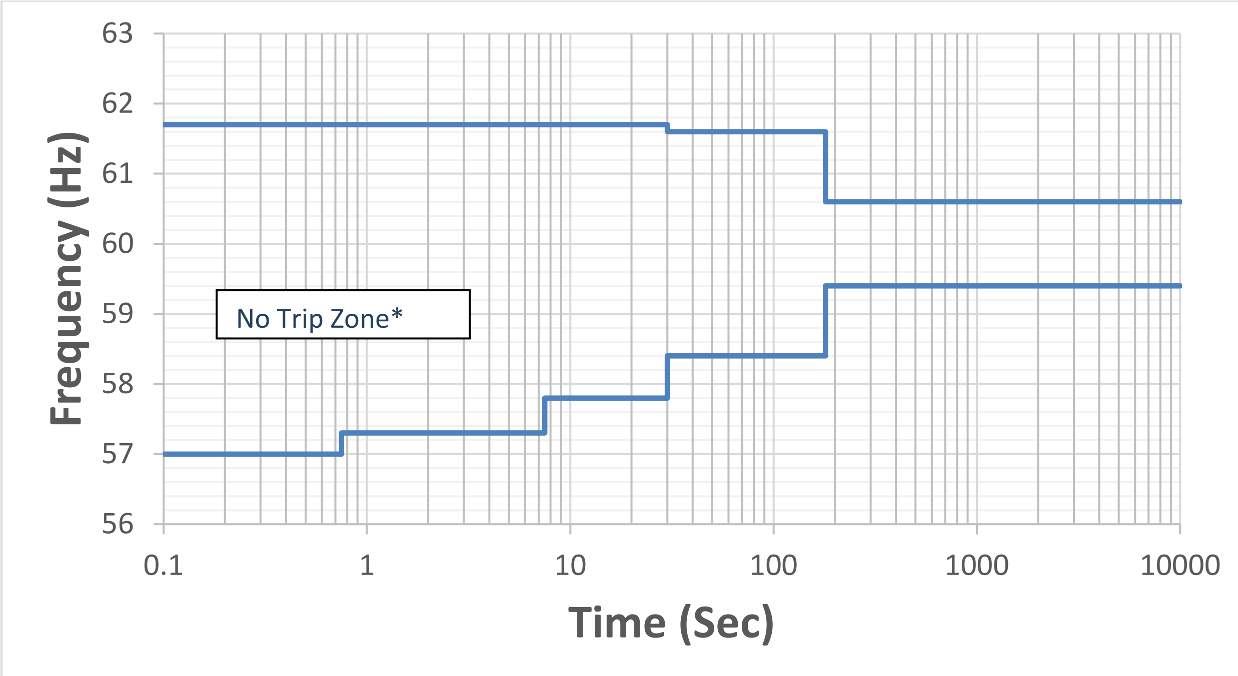

Figure 2: Western Interconnection Boundaries

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

Table 2: 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[11]	≤57.0	Instantaneous[11]
≥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

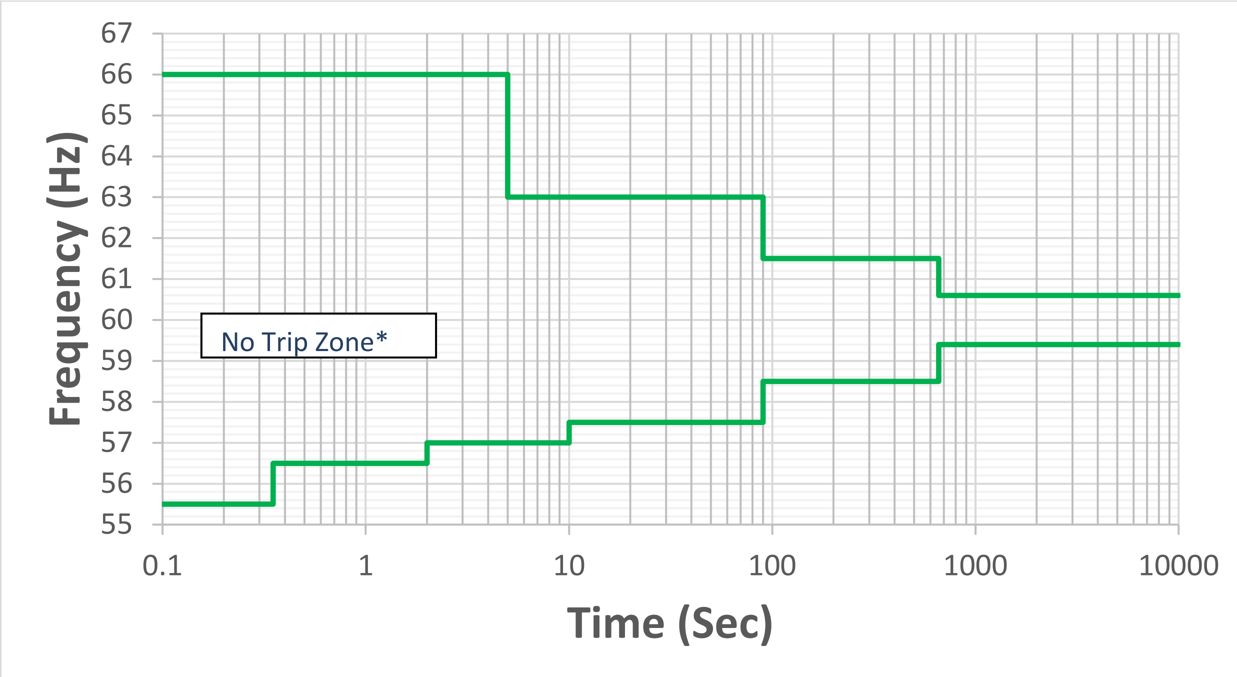

Figure 3: Quebec Interconnection Boundaries

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

Table 3: 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[11]	<55.5	Instantaneous[11]
≥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

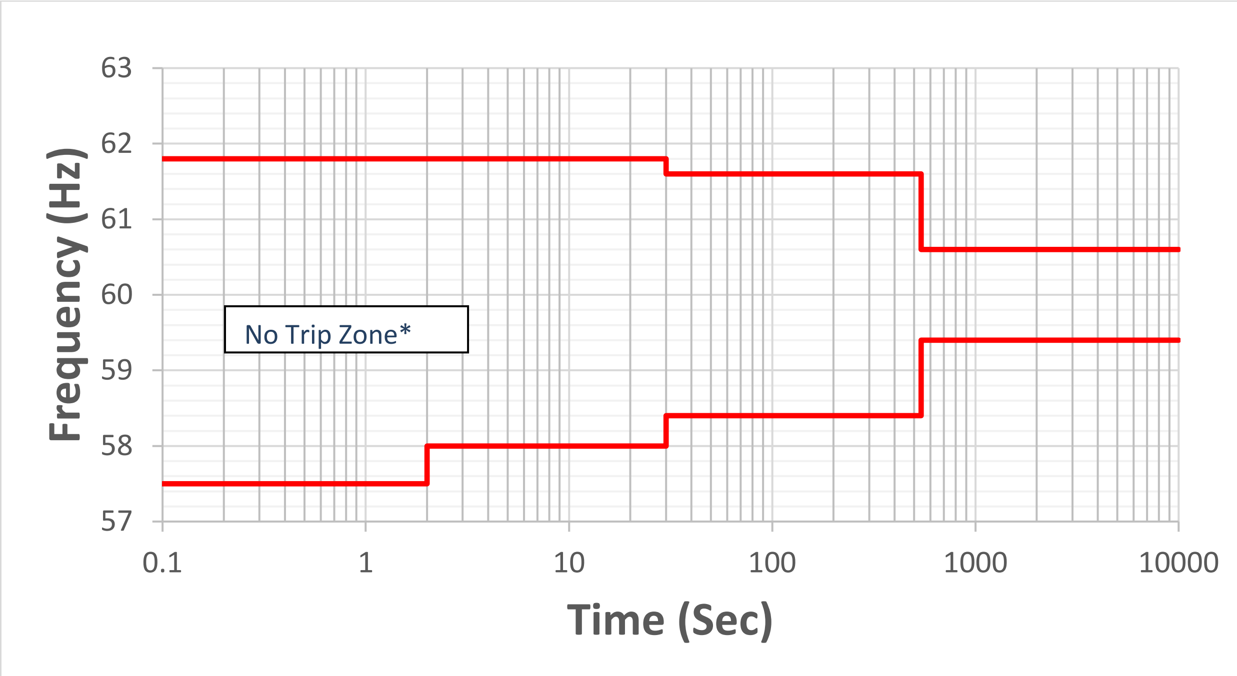

Figure 4: ERCOT Interconnection Boundaries

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

Table 4: 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[11]	≤57.5	Instantaneous[11]
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024 — Attachment 2

(Voltage No-Trip Boundaries – Eastern, Western, and ERCOT Interconnections)

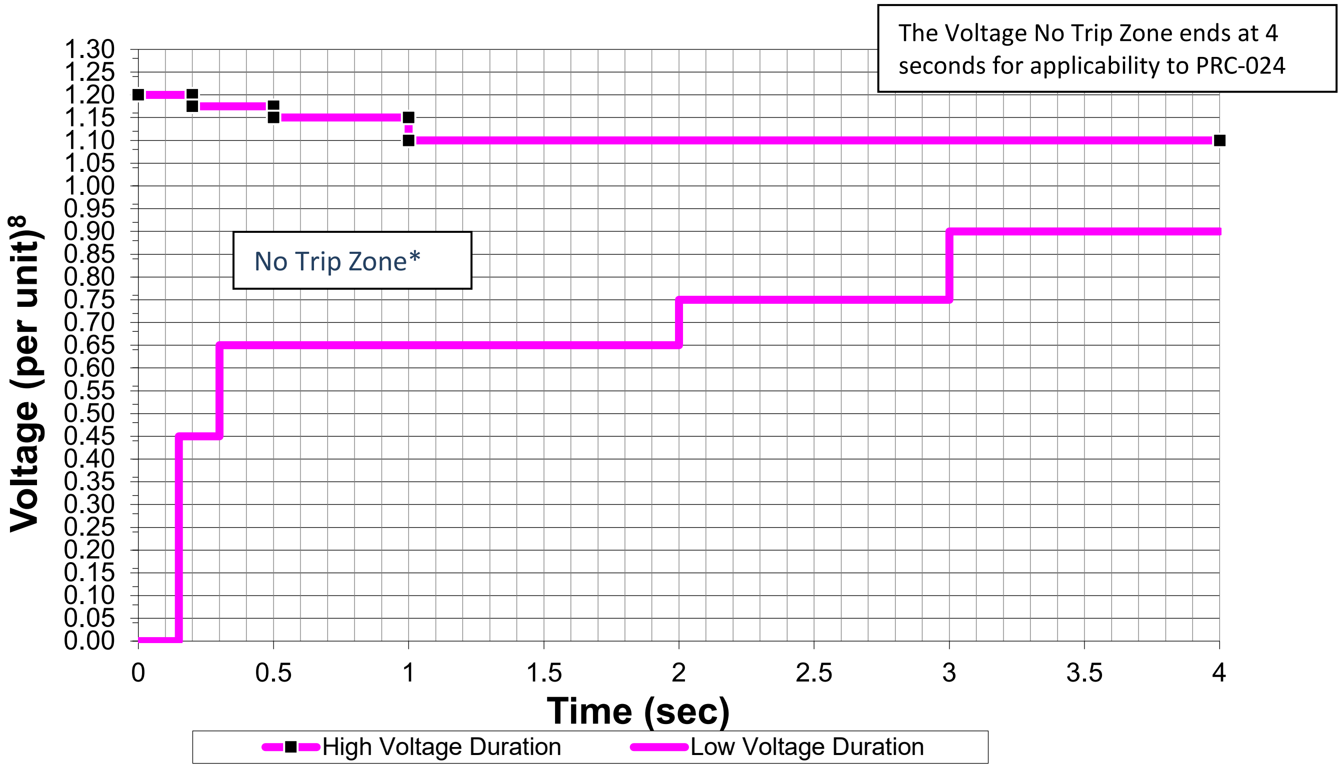

Figure 5: Voltage No-Trip Boundaries – Eastern, Western, and ERCOT Interconnections

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

Table 5: Voltage Boundary Data Points

High Voltage Duration		Low Voltage Duration	
Voltage (per unit)	**Minimum Time (sec)**	**Voltage (per unit)**	**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

Attachment 2: Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections

Boundary Details:

1. Unless otherwise specified by the Transmission Planner, the per unit voltage base for these boundaries is the nominal transmission system voltage (e.g., 100 kV, 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 400 kV, 500 kV, 765 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 boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase per unit voltage.
5. For applicability to PRC-024, the "no trip zone" ends at 4 seconds.

Evaluating Protection Settings:

The voltage values in the Attachment 2 voltage boundaries are voltages at the high-side of the GSU/MPT. For 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 conditions when evaluating protection settings:

a. The most probable real and reactive loading conditions for the synchronous generator, type 1 or 2 wind resources, or synchronous condenser under study.
b. All installed wind resource 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 or the collector station and the high-side of the GSU/MPT.
d. For dynamic simulations, the synchronous generator or condenser automatic voltage regulator is in automatic voltage control mode with associated limiters in service.

PRC-024— Attachment 2A

(Voltage No-Trip Boundaries – Quebec Interconnection)

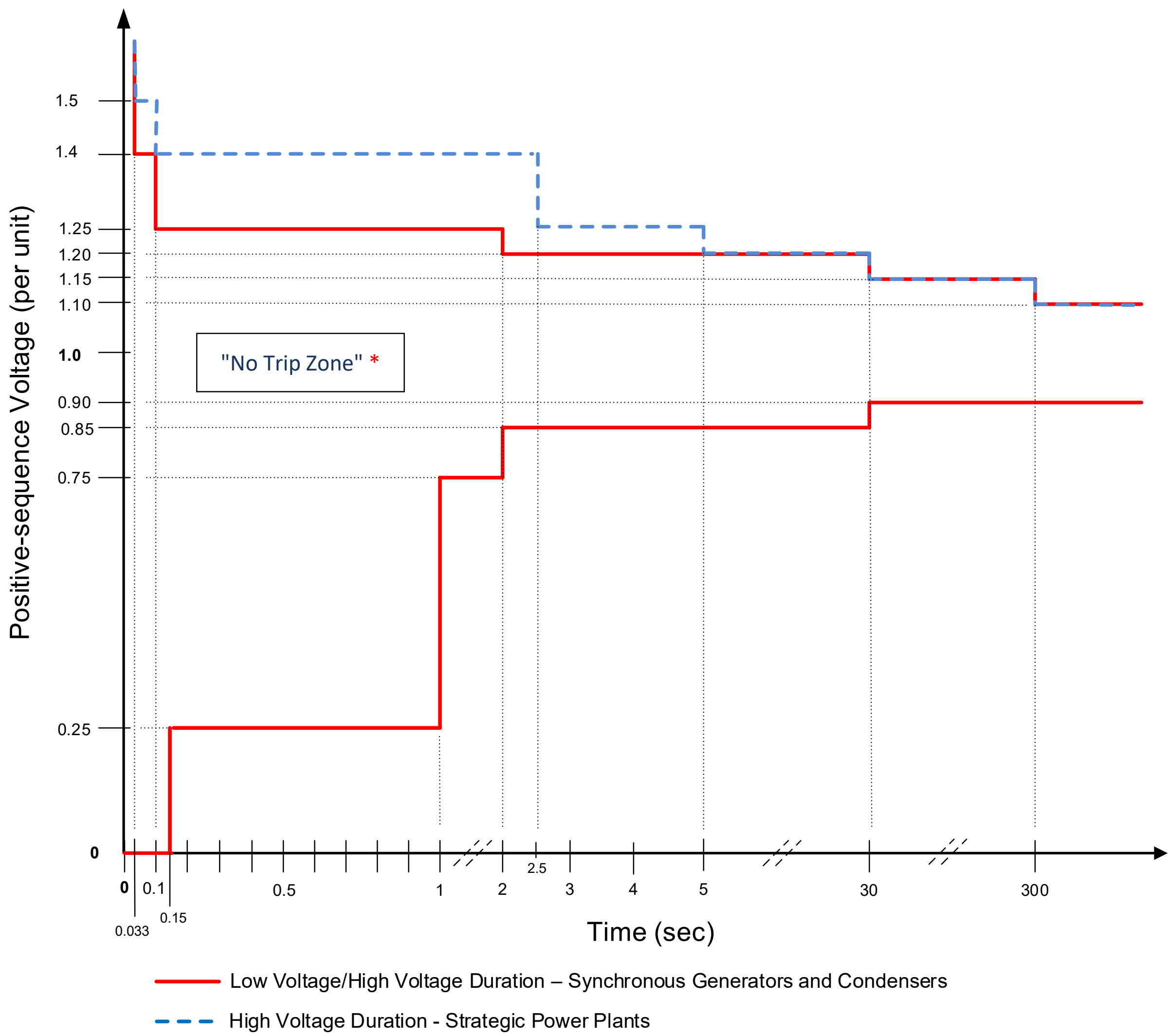

Figure 6: Voltage No-Trip Boundaries – Quebec Interconnection

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

Table 6: High Voltage Boundary Data Points – Quebec Interconnection

High Voltage Duration for all Synchronous Generators and Condensers		High Voltage Duration for strategic Power Plants	
Voltage (per unit)	Minimum Time (sec)	Voltage (per unit)	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 7: Low Voltage Boundary Data Points – Quebec Interconnection

Low Voltage Duration for all Synchronous Generators and Condensers	
Voltage (per unit)	Minimum Time (sec)
<0.25	0.15
<0.75	1.00
<0.85	2.00
<0.90	30
≥0.90	continuous

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 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.

Exhibit A-2

PRC-024-4 Redline

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

Draft 3 of PRC-024-4 is posted for final ballot. Non-substantive corrections were identified during the last additional ballot. This draft includes those corrections.

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023
25-day formal comment period with initial ballot	March 27 - April 22, 2024
15-day formal comment period and additional ballot	June 18 – July 8, 2024

Anticipated Actions	Date
Final ballot	September 25 – September 30, 2024
Board Adoption	October 8, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

A. Introduction

1. **Title:** **Frequency and Voltage Protection Settings for Synchronous Generators~~ing~~, Type 1 and Type 2 Wind Resources, and Synchronous Condensers**

2. **Number:** **PRC-024-4~~3~~**

3. **Purpose:** To assure~~set~~ that protection of~~ such that~~ synchronous generators~~ing~~, type 1 and type 2 wind resource~~(s)~~, and synchronous condensers do not cause tripping ~~remain connected~~ during defined frequency and voltage excursions in support of the Bulk ~~Electric~~ Power System (BP~~E~~S).

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Generator Owners that apply protection listed in Section 4.2.1 or 4.2.2.

   4.1.2 Transmission Owners that apply protection listed in Section 4.2.2.

   ~~4.1.2~~4.1.3 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~~4.1.4 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 Bulk Electric (BES) synchronous generators~~ing resource(s)~~.

   4.2.1.2 BES GSU transformer(s) for synchronous generators.

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

   4.2.1.4 Individual dispersed power producing type 1 or type 2 wind resource(s) identified in the BES Definition, Inclusion I4.

---

[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.

4.2.1.5 Elements that are designed primarily for the delivery of capacity from multiple synchronous generators connecting to a common bus or~~the~~ individual dispersed power producing type 1 or type 2 wind resources 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 multiple synchronous generators connecting to a common bus or MPT of individual dispersed power producting type 1 or type 2 wind resource~~(~~s~~)~~ as identified in the BES Definition, Inclusion I4.

4.2.2 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 transmission connected synchronous condensers; or (ii) provide signals to trip transmission connected synchronous condenser and are applied to the following:

4.2.2.1 BES synchronous condensers

4.2.2.2 BES step-up transformer(s) for synchronous condensers.

4.2.2.3 High-side of the synchronous condenser-connected unit auxiliary transformer (UAT).

~~4.2.2~~**4.2.3** **Exemptions:** Protection on all auxiliary equipment within the synchronous generator~~ing~~, type 1 or type 2 wind resource, or synchronous condenser Facility.

5. Effective Date: See the Implementation Plan for PRC-024-4~~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~~

B. Requirements and Measures

R1. Each Generator Owner and Transmission Owner shall set ~~its~~ applicable frequency protection[5] in accordance with PRC-024-4 Attachment 1 such that the applicable protection does not cause the ~~generating resource~~Facility to which it is applied to trip ~~or cease injecting current~~ within the "no trip zone" during a frequency excursion with the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Applicable frequency protection may 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.

M1. Each Generator Owner and Transmission Owner shall have evidence that the -applicable frequency protection has been set in accordance with Requirement R1, such as dated setting sheets, calibration sheets, calculations, or other documentation.

R2. Each Generator Owner and Transmission Owner shall set its applicable voltage protection[6~~5~~] in accordance with PRC-024-4 Attachment 2, such that the applicable protection does not cause the ~~generating resource~~Facility to which it is applied to trip ~~or cease injecting current~~ within the "no trip zone" during a voltage excursion at the high- side of the GSU or MPT,- 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-024-4 Attachment 2, then the Generator Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- Applicable voltage protection may be set to trip ~~or cease injecting current~~ during a voltage excursion within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M2. 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.

[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 synchronous generat~~ors~~ing, type 1 or type 2 wind resource(s), or synchronous condenser(s); or (ii) provide signals to ~~the generating resource(s) to either~~ trip ~~or cease injecting current~~the same Facilties.

[6] Ibid

R3. Each Generator Owner and Transmission Owner shall document each known regulatory or equipment limitation[7] that prevents ~~an applicable generating resource(s)~~its Facility, with applicable frequency or voltage protection from meeting the 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]*

3.1. The Generator Owner and Transmission 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 and Transmission Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations 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.

R4. Each Generator Owner and Transmission Owner shall provide its applicable protection settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated Facility ~~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 settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of protection setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Generator Owner and Transmission Owner shall have evidence that it communicated applicable 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.

[7] Excludes limitations caused by the setting capability of the frequency, voltage, and volts per hertz protective relays applied to the synchronous ~~for the~~ generat~~ing~~ors, type 1 or type 2 wind resource(s), and synchronous condenser(s). This does not exclude limitations originating in the equipment protected by the relay. ~~This also does not exclude limitations of frequency, voltage, and volts per hertz protection embedded in control systems~~.

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.

   1.2. Evidence Retention: 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 and Transmission Owner shall keep data or evidence Requirement R1 through R4; for five~~3~~ years or until the next audit, whichever is longer.
   - If a Generator Owner or Transmission 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.

   1.3. Compliance Monitoring and Assessment 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.

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 or Transmission Owner failed to set its applicable frequency protection so that it does not trip ~~or cease injecting current~~ according to Requirement R1.
R2.	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~~ according to Requirement R2.
R3.	The Generator Owner or Transmission 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	The Generator Owner or Transmission 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	The Generator Owner or Transmission 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	The Generator Owner or Transmission Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the 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.	OR The Generator Owner or Transmission Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4.	The Generator Owner or Transmission Owner provided its protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 90 calendar days but less than	The Generator Owner or Transmission Owner provided its protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 120 calendar days but less than or equal to 150	The Generator Owner or Transmission Owner failed to provide its protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner failed to provide protection settings within 150 calendar days of a written request.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		or equal to 120 calendar days of a written request.	calendar days of a written request.	

D. Regional Variances

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[8~~5~~] in accordance with PRC-024 Attachment 2A~~a~~, such that the applicable protection does not cause the ~~generating resource~~Facility to which it is applied to trip within the "no trip zone" ~~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".
- Applicable voltage protection may ~~The generating resource(s) are permitted to~~ be set to trip ~~or to cease injecting current~~ during a voltage excursion within a portion of ~~bounded by~~ the "no trip zone" of PRC-024 Attachment 2A~~a~~ 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~~a~~, then the Generator Owner or Transmission Owner may set its protection

[8] 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 synchronous generator(s), type 1 or type 2 wind resource(s), or synchronous condenser(s); or (ii) provide signals to trip the same Facilities.

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~~a~~ and notify, within 30 calendar days of its designation, each Generator Owner or Transmission Owner that owns facilities[9] 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.

[9] Facilities in the strategic power plants include facilities with synchronous generator(s) 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~~a~~.

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.

E. Associated Documents

Implementation Plan

~~E.~~A. ~~Associated Documents~~

~~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	February 6, 2020	Adopted by the NERC Board of Trustees	Standard revised in Project 2018-04
3	July 9, 2020	FERC Letter Order approved PRC-024-3. Docket No. RD20-7-000	
3	July 17,2020	October 1, 2022	Effective Date
4	August 2, 2024	Revisions made by the 2020-02 Drafting Team	Revision accounts for changes with PRC-029-1 as part of Milestone 2 of NERC's work plan to address FERC Order No. 901.

Attachment 1

(Frequency No Trip Boundaries by Interconnection[10])

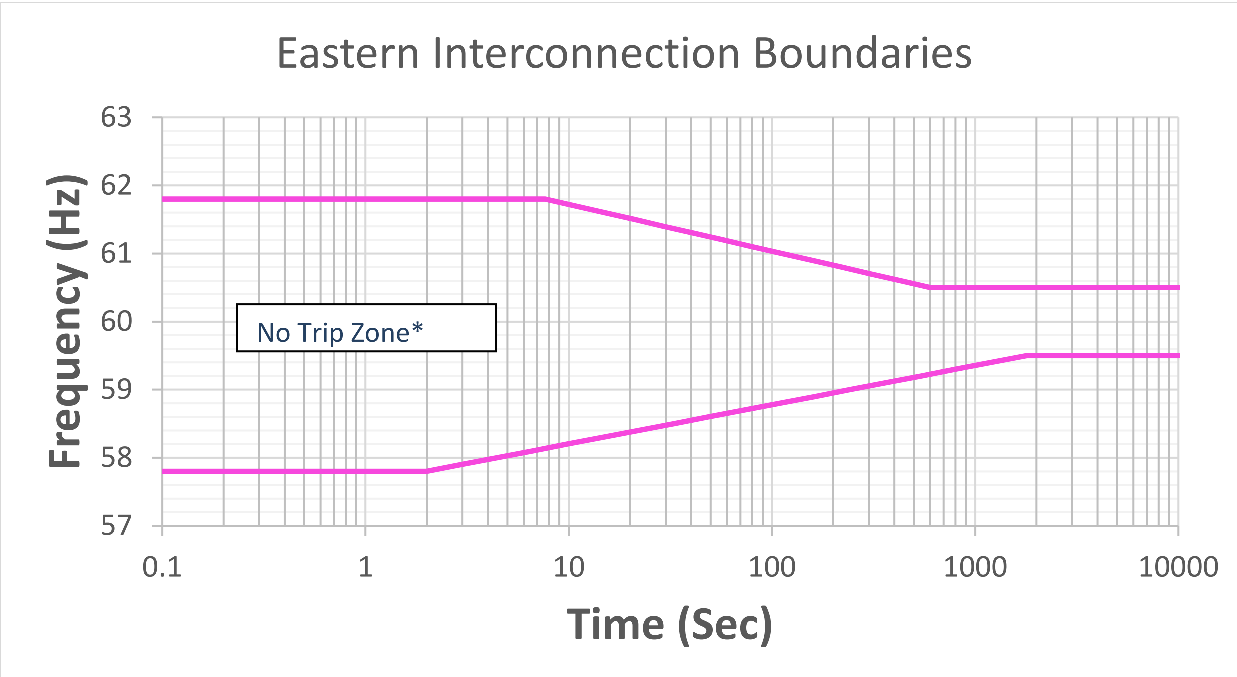

Figure 1: Eastern Interconnection Boundaries

~~Figure 1~~

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

Table 1: 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[11]	≤57.8	Instantaneous[11]
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$

[10] 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.

[11] 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.

<60.5	Continuous operation	> 59.5	Continuous operation

~~*Table 1*~~

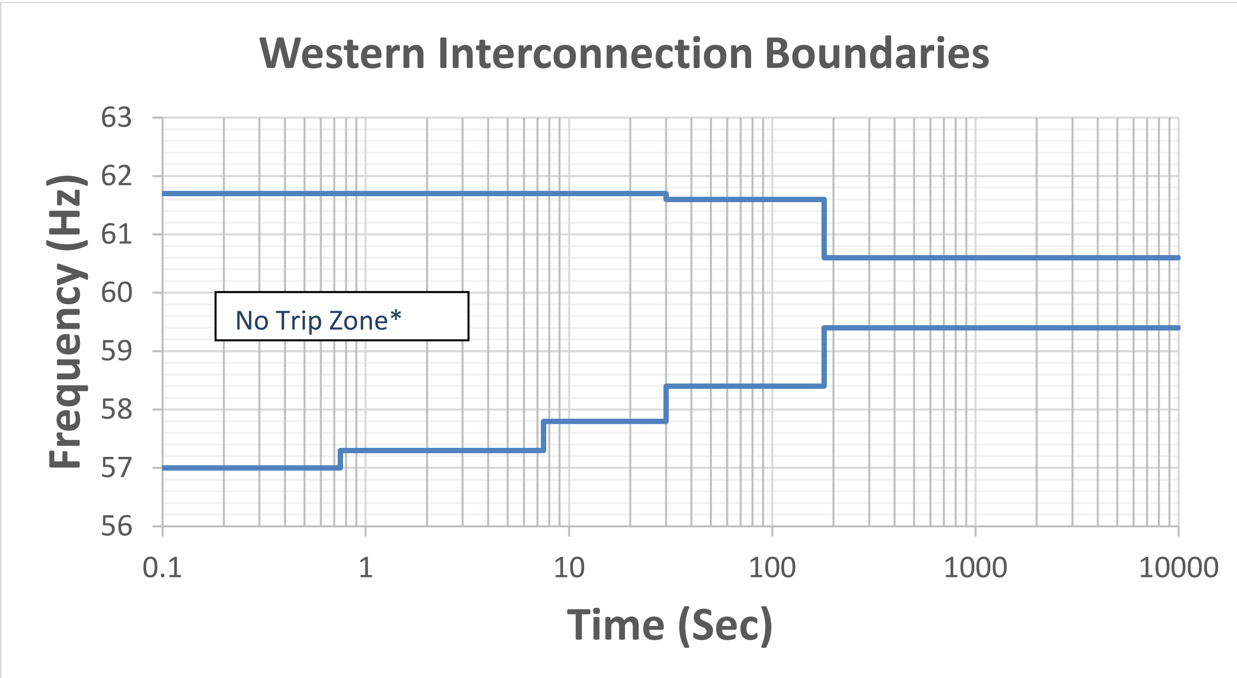

Figure 2: Western Interconnection Boundaries

~~*Figure 2*~~

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

Table 2: 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[11]	≤57.0	Instantaneous[11]
≥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*~~

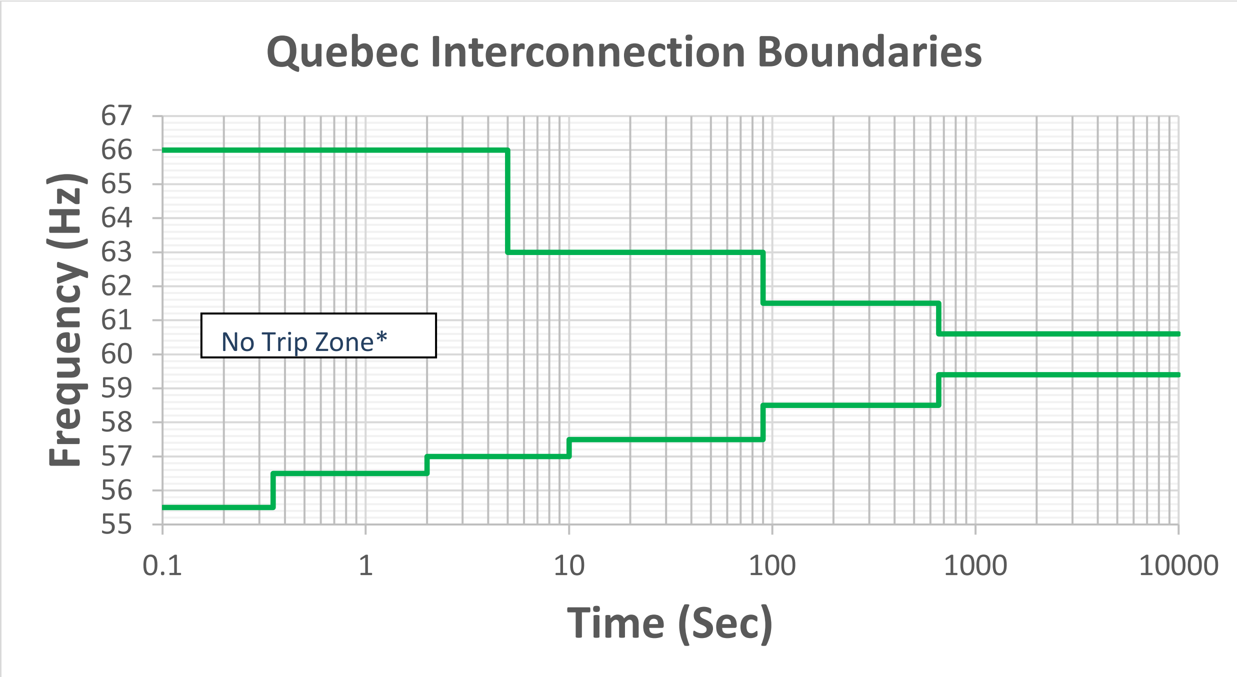

Figure 3: Quebec Interconnection Boundaries

~~Figure 3~~

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

Table 3: 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[11]	<55.5	Instantaneous[11]
≥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~~

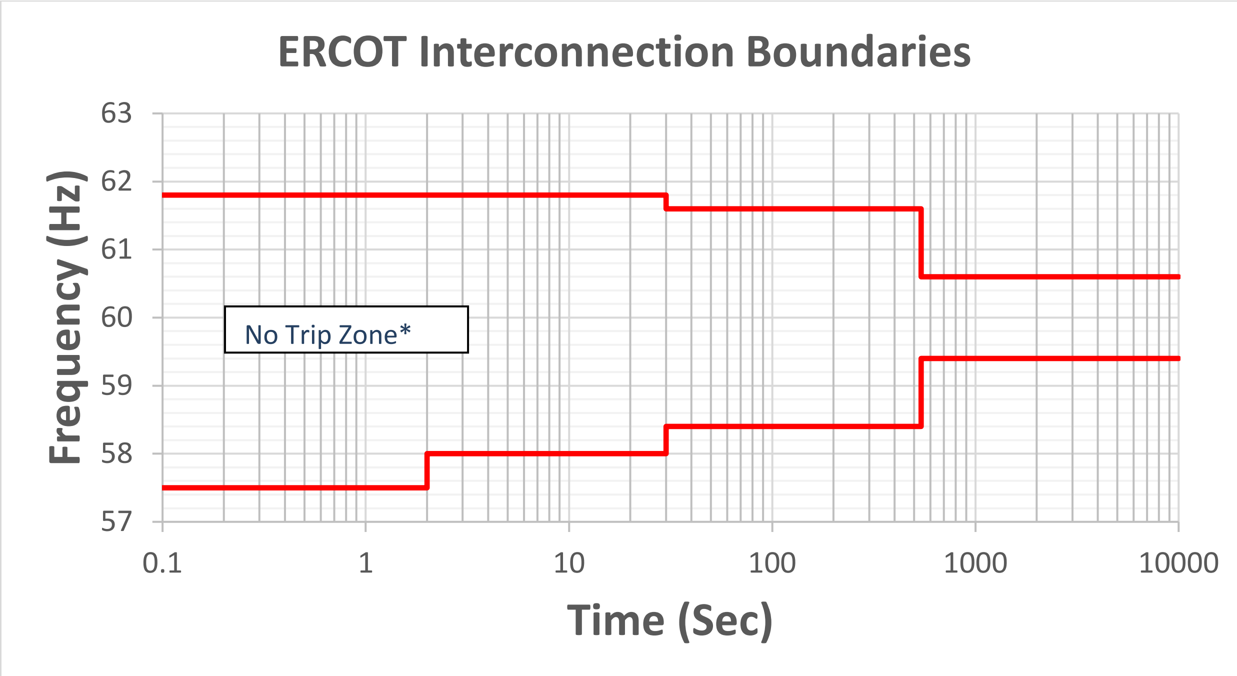

Figure 4: ERCOT Interconnection Boundaries

~~Figure 4~~

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

Table 4: 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[11]	≤57.5	Instantaneous[11]
≥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

(Voltage No-Trip Boundaries – Eastern, Western, and ERCOT Interconnections)

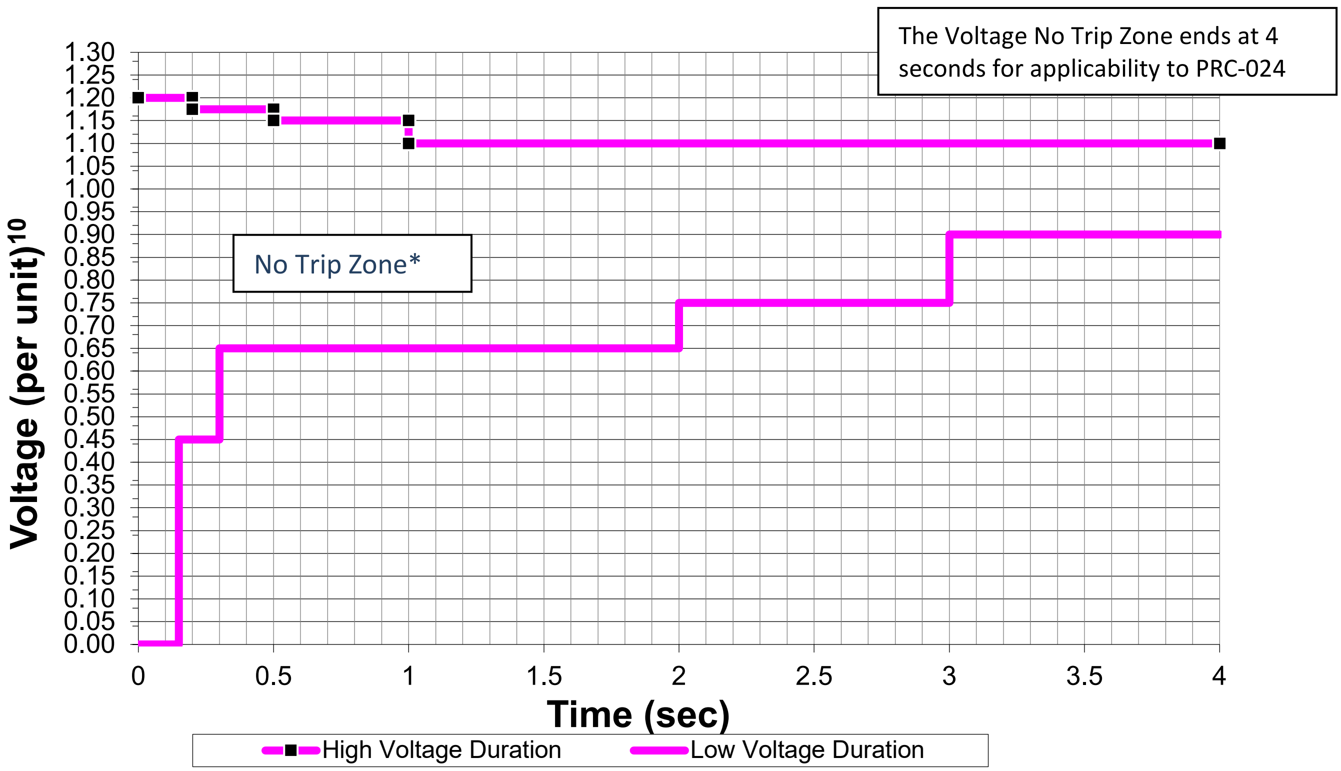

Figure 5: Voltage No-Trip Boundaries – Eastern, Western, and ERCOT Interconnections

~~[12]*Figure 1*~~

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

Table 5: 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

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

~~Table 1~~

Attachment 2: Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections

Boundary Details:

1. Unless otherwise specified by the Transmission Planner, the per unit voltage base for these boundaries is the nominal transmission system voltage (e.g., 100 kV, 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 400 kV, 500 kV, 765 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 boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase per unit voltage.
5. For applicability to PRC-024, the “no trip zone” ends at 4 seconds.

Evaluating Protection Settings:

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 conditions when evaluating protection settings:

a. The most probable real and reactive loading conditions for the synchronous generator, type 1 or 2 wind resources, or synchronous condenser ~~unit~~ under study.
b. All installed wind resource ~~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 or the collector station and the high side of the GSU/MPT.
d. For dynamic simulations, the synchronous generator or condenser automatic voltage regulator is in automatic voltage control mode with associated limiters in service.

PRC-024— Attachment 2a

(Voltage No-Trip Boundaries – Quebec Interconnection)

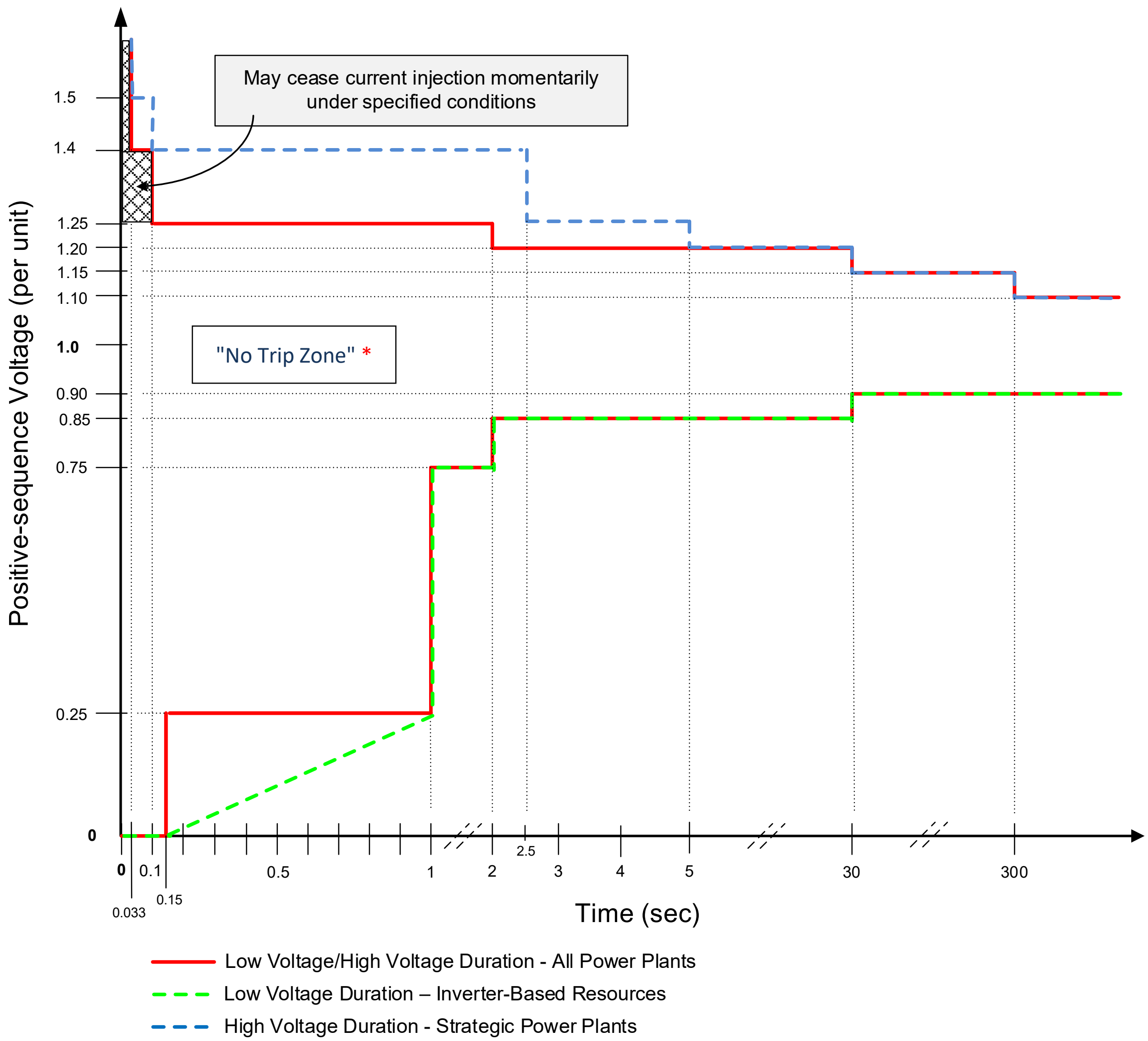

Figure 6: Voltage No-Trip Boundaries – Quebec Interconnection

~~*Figure 1*~~

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

~~1~~Table 6: High 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*~~

Table 7: Low 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~~a~~: 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.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-3

PRC-029-1

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

Final Draft of PRC-029-1 is posted for a formal comment and additional ballot.

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023
25-day formal comment period and initial ballot	March 27 – April 22, 2024
15-day formal comment period and additional ballot	June 18 – July 8, 2024
15-day formal comment period and additional ballot	July 22 – August 12, 2024
14-day formal comment period and additional ballot	September 17 – September 30, 2024
Final Ballot	None Required
Board adoption	October 8, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Ride-through: The plant/facility remains connected and continues to operate through voltage or frequency system disturbances.

A. Introduction

1. **Title:** **Frequency and Voltage Ride-through Requirements for Inverter-based Resources**
2. **Number:** **PRC-029-1**
3. **Purpose:** To ensure that IBRs Ride-through to support the Bulk Power System (BPS) during and after defined frequency and voltage excursions.
4. **Applicability:**

4.1 Functional Entities:

4.1.1. Generator Owner

4.2 Facilities:

4.2.1. Bulk Electric System (BES) IBRs

4.2.2. Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Effective Date: See Implementation Plan for Project 2020-02 – PRC-029-1

Standard-only Definition: None

B. Requirements and Measures

R1. Each Generator Owner shall ensure the design and operation is such that each IBR meets or exceeds Ride-through requirements, in accordance with the "must Ride-through[1] zone" as specified in Attachment 1, except in the following conditions: *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

- The IBR needed to electrically disconnect in order to clear a fault;
- The voltage at the high-side of the main power transformer[2] went outside an accepted hardware limitation, in accordance with Requirement R4;
- The instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer and is initiated by a non-fault switching event on the transmission system[3]; or
- The Volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

M1. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to Ride-through requirements, as specified in Requirement R1. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) to demonstrate that the operation of each IBR did adhere to Ride-through requirements, as specified in Requirement R1. If the Generator Owner choose to utilize Ride-through exemptions that occur within the "must Ride-through zone" and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) data to demonstrate that the IBR failed to Ride-through during a phase jump of greater than or equal to 25 electrical degrees, and documentation from their Transmission Planner, Reliability Coordinator, Planning Coordinator, or Transmission Operator that a non-fault initiated switching event occurred.

R2. Each Generator Owner shall ensure the design and operation is such that the voltage performance for each IBR adheres to the following during a voltage excursion, unless a documented hardware limitation exists in accordance with Requirement R4. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

2.1. While the voltage at the high-side of the main power transformer remains within the continuous operation region as specified in Attachment 1, each IBR shall:

[1] Includes no tripping associated with phase lock loop loss of synchronism.

[2] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for IBRs. In case of IBR connecting via a dedicated Voltage Source Converter High Voltage Direct Current (VSC-HVDC), the main power transformer is the main power transformer on the receiving end.

[3] Current blocking mode may be used for non-fault initiated phase jumps greater than 25 degrees in order to prevent tripping.

2.1.1 Continue to deliver the pre-disturbance level of Real Power or available Real Power[4], whichever is less.[5]

2.1.2 Continue to deliver Reactive Rower up to its Reactive Power limit and according to its controller settings.

2.1.3 Prioritize Real Power or Reactive Power when the voltage is less than 0.95 per unit, the voltage is within the continuous operating region, and the IBR cannot deliver both Real Power and Reactive Power due to a current limit or Reactive Power limit, unless otherwise specified through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.2. While voltage at the high-side of the main power transformer is within the mandatory operation region as specified in Attachment 1, each IBR shall exchange current, up to the maximum capability to provide voltage support, on the affected phases during both symmetrical and asymmetrical voltage disturbances, either under[6]:

- Reactive Power priority by default; or
- Real Power priority if required through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.3. While voltage at the high-side of the main power transformer is within the permissive operation region, as specified in Attachment 1, each IBR may operate in current blocking mode if necessary to avoid tripping. Otherwise, each IBR shall follow the requirements for the mandatory operation region in Requirement R2.2.

2.3.1 If an IBR enters current blocking mode, it shall restart current exchange in less than or equal to five cycles of positive sequence voltage returning to a continuous operation region or mandatory operation region.

2.4. Each IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable high voltage thresholds and time durations in its response as voltage recovers from the mandatory or permissive operation regions to the continuous operation region.

2.5. Each IBR shall restore Real Power output to the pre-disturbance or available level[7] (whichever is lesser) within 1.0 second when the voltage at the high-side of the main power transformer returns from the mandatory operation region or

[4] "Available Real Power" refers to changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes of facility Real Power attributed to IBR tripping in whole or part.
[5] Except if this would occur during a frequency excursion. The Real Power response should recover in accordance with the primary frequency controller.
[6] In either case and if required, the magnitude of Real Power and reactive current shall be as specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.
[7] "Available Real Power" refers to changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes of facility Real Power attributed to IBR tripping in whole or part.

permissive operation region (including operating in current blocking mode) to the continuous operation region, as specified in Attachment 1, unless an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires a lower post-disturbance Real Power level requirement or requires a different post-disturbance Real Power restoration time through other mechanisms.[8]

M2. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to requirements, as specified in Requirement R2. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) data to demonstrate that the operation of each IBR did adhere to performance requirements, as specified in Requirement R2, during each voltage excursion measured at the high-side of the main power transformer. Regarding R2.1.3, R2.2, and R2.5, the Generator Owner shall retain evidence of receiving such performance requirements, (e.g., email exchange, contract information) if the Transmission Planner, Transmission Operator, Reliability Coordinator, or Planning Coordinator has required the Generator Owner through other mechanisms to follow performance requirements other than those in Requirement R2 (e.g., ramp rates, Reactive Power prioritization).

R3. Each Generator Owner shall ensure the design and operation is such that each IBR meets or exceeds Ride-through requirements during a frequency excursion event whereby the System frequency remains within the "must Ride-through zone" according to Attachment 2 and the absolute rate of change of frequency (RoCoF)[9] magnitude is less than or equal to 5 Hz/second, unless a documented hardware limitation exists in accordance with Requirement R4. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

M3. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to Ride-through requirements, as specified in Requirement R3. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) data to demonstrate the operation of each IBR did adhere to Ride-through requirements, as specified in Requirement R3, during each frequency excursion event measured at the high-side of the main power transformer.

R4. Each Generator Owner identifying an IBR that is in-service by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1-R3, and requires an exemption from specific

[8] Except if this would occur during a frequency excursion. The Real Power response should recover in accordance with the primary frequency controller.

[9] Rate of change of frequency (RoCoF) is calculated as the average rate of change for multiple calculated system frequencies for a time period of greater than or equal to 0.1 second. RoCoF is not calculated during the fault occurrence and clearance.

Ride-through criteria shall:[10] *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1. This documentation shall include:

4.1.1 Identifying information of the IBR (name and facility number);

4.1.2 Which aspects of Ride-through requirements that the IBR would be unable to meet and the capability of the hardware due to the limitation;

4.1.3 Identification of the specific piece(s) of hardware causing the limitation;

4.1.4 Technical documentation verifying the limitation is due to hardware that would need to be physically replaced to meet all Ride-through criteria, and that the limitation cannot be remedied by software updates or setting changes; and

4.1.5 Information regarding any plans to remedy the hardware limitation (such as an estimated date).

4.2. Provide a copy of the information detailed in Requirement R4.1, except for any material considered by the original equipment manufacturer to be proprietary information, to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the Compliance Enforcement Authority (CEA) no later than 12 months following the effective date of PRC-029-1.[11]

4.2.1 Provide any response for additional information requested by the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA to the requestor within 90 days of the request.

4.2.2 Provide a copy of the acceptance of a hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of receiving the acceptance.[12]

4.3. Each Generator Owner with a previously accepted limitation that replaces the hardware causing the limitation shall document and communicate such a hardware change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the hardware change.

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[10] The exemption requests for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

[11] To the extent the original equipment manufacturer considers any material to be proprietary, the Generator Owner is required to share this proprietary material only with the CEA.

[12] Acceptance by the CEA is verification that the information provided includes all information listed in Requirement R4.1.

4.3.1 When existing hardware causing the limitation is replaced, the exemption for that Ride-through criteria no longer applies.

M4. Each Generator Owner submitting for an exemption for an IBR that is in-service by the effective date of PRC-029-1, shall have evidence of submission to the CEA consistent with the information listed in Requirement R4.1. Each Generator Owner shall have evidence of communicated copies of each submission in accordance with Requirement R4.2 and to the associated entities described in Requirement R4.2. Acceptable types of evidence for submittals include, but are not limited to, meeting minutes, agreements, copies of procedures or protocols in effect, or email correspondence. Acceptable types of evidence for a hardware limitation may include, but is not limited to damage curves provided by the original equipment manufacturer. Each Generator Owner that receives a request for additional information under Requirement R4.2.1 shall have evidence of providing that information within 90 days. Each Generator Owner that replaces hardware at an IBR that is directly associated with an accepted exemption and that hardware is the cause for the limitation, shall have evidence of communicating the hardware change to the associated entities described in Requirement R4.3 within 90 days of the hardware replacement.

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.

1.2. Evidence Retention: 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.

- Each Generator Owner shall retain evidence with Requirements R1, R2, and R3 in this standard for 36 calendar months or the date of the last audit, whichever is greater.
- Each Generator Owner shall retain evidence with Requirement R4 in this standard for five calendar years or the date of the last audit, whichever is greater.

1.3. Compliance Monitoring and Enforcement 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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The Generator Owner failed to ensure the design capability of each applicable IBR to Ride-through in accordance with Attachment 1, except for those conditions identified in Requirement R1.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to Ride-through requirements in accordance with Attachment 1, except for those conditions identified in Requirement R1.
R2.	The Generator Owner failed to ensure the design capability of each applicable IBR to adhere to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.
R3.	The Generator Owner failed to ensure the design capability of each applicable IBR to Ride-through in accordance with Attachment 2, unless a documented hardware limitation exists in accordance with Requirement R4.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to Ride-through requirements in accordance with Attachment 2, unless a documented hardware limitation exists in accordance with Requirement R4.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 12 months, but less than or equal to 15 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 90 days but less than or equal to 120 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 90 days but less than or equal to 120 days after receiving the acceptance of a hardware limitation by the CEA. OR	The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 15 months, but less than or equal to 18 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 120 days, but less than or equal to 150 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 120 days but less than or equal to 150 days after receiving the acceptance of a hardware limitation by the CEA.	The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 18 months, but less than or equal to 24 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 150 days but less than or equal to 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 150 days but less than or equal to 180 days after receiving the acceptance of a hardware limitation by the CEA. OR	The Generator Owner failed to document complete information for IBR identified with known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1, R2, or R3. OR The Generator Owner failed to provide a copy to the applicable entities as detailed in Requirement R4.2 within 24 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and CEA more than 90 calendar days but less than or equal to 120 calendar days after the change to the hardware.	OR The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 120 calendar days but less than or equal to 150 calendar days after the change to the hardware.	The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 150 calendar days but less than or equal to 180 calendar days after the change to the hardware.	entities as detailed in Requirement R4.2.2 more than 180 days after receiving the acceptance of a hardware limitation by the CEA. The Generator Owner with a previously communicated hardware limitation that replace the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s),Reliability Coordinator(s), and CEA more than 180 days after the change to the hardware.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan .

Version History

Version	Date	Action	Change Tracking
1	10/8/24	Draft 4 approved by the NERC Board of Trustees	
1	10/16/24	Draft4_Errata approved by the Standards Committee	

Attachment 1: Voltage Ride-Through Criteria

Table 1: Voltage Ride-through Requirements for AC-Connected Wind IBR [13]

Voltage (per unit)[14]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[15]	N/A
≥ 1.10	Mandatory Operation Region	1.0
> 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90	Mandatory Operation Region	3.00
< 0.70	Mandatory Operation Region	2.50
< 0.50	Mandatory Operation Region	1.20
< 0.25	Mandatory Operation Region	0.16
< 0.10	Permissive Operation Region	0.16

Table 2: Voltage Ride-through Requirements for All Other IBR

Voltage (per unit)[16]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[17]	N/A
> 1.10	Mandatory Operation Region	1.0
> 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90	Mandatory Operation Region	6.00
< 0.70	Mandatory Operation Region	3.00
< 0.50	Mandatory Operation Region	1.20
< 0.25	Mandatory Operation Region	0.32
< 0.10	Permissive Operation Region	0.32

[13] Type 3 and type 4 wind resources directly connected to the AC Transmission System.
[14] Refer to bullet #4 below.
[15] These conditions are referred to as the "may Ride-through zone".
[16] Refer to bullet #4 below.
[17] These conditions are referred to as the "may Ride-through zone".

1. Table 1 applies to type 3 and type 4 wind IBR or hybrid IBR that include wind, unless connected via a dedicated Voltage Source Converter - High Voltage Direct Current (VSC-HVDC) transmission facility.
2. Table 2 applies to all other IBR types not covered in Table 1; including, but not limited to, the following facilities:
   a. IBR, regardless of their energy resource, interconnecting via a dedicated VSC-HVDC transmission facility.
   b. Other IBR or hybrid IBR consisting of photovoltaic (PV) and BESS.
3. The applicable voltage for VSC-HVDC system with a dedicated connection to an IBR is on the AC side of the transformer(s) that is (are) used to connect the VSC-HVDC system to the interconnected transmission system.
4. The voltage base for per unit calculation is the nominal phase-to-ground or phase-to-phase transmission system voltage unless otherwise defined by the Planning Coordinator, Transmission Planner, or Transmission Owner.
5. The applicable voltage for Tables 1 and 2 is identified as the voltage max/min of phase-to-neutral or phase-to-phase fundamental root mean square (RMS) voltage at the high-side of the main power transformer.
6. Tables 1 and 2 are only applicable when the frequency is within the “must Ride-through zone” as specified in Figure 1 of Attachment 2.
7. At any given voltage value, each IBR shall Ride-through unless the time duration at that voltage has exceeded the specified minimum Ride-through time duration. If the voltage is continuously varying over time, it is necessary to add the duration within each band of Tables 1 and 2 over any 10 second time period.
8. The specified duration of the mandatory operation regions and the permissive operation regions in Tables 1 and 2 is cumulative over one or more disturbances within any 10 second time period.
9. The IBR may trip for more than four deviations of the applicable voltage at the high-side of the main power transformer outside of the continuous operation region within any 10 second time period.
10. Instantaneous trip settings based on instantaneously calculated voltage measurements with less than filtering lengths of one cycle (16.6 millisecond) are not permissible.
11. The “must Ride-through zone” is the combined area of the mandatory operating regions, the continuous operating regions, and the permissive operating region. All area outside of these operating regions is referred to as the “may Ride-through zone”.

Attachment 2: Frequency Ride-Through Criteria

Table 3: Frequency Ride-through Capability Requirements

System Frequency (Hz)	Minimum Ride-Through Time (sec)
> 61.8	May trip
> 61.2	299
≤ 61.2 and ≥ 58.8	Continuous
< 58.8	299
< 57.0	May trip

1. Frequency measurements are taken at the high-side of the main power transformer.
2. Frequency is measured over a period of time (typically 3-6 cycles) to calculate system frequency at the high-side of the main power transformer.
3. Instantaneous or single points of measurement may not be used in the determination of control settings.
4. At any given frequency value, each IBR shall Ride-through unless the time duration at that frequency has exceeded the specified minimum ride-through time duration.
5. The specified durations of Table 3 are cumulative over one or more disturbances within a 10-minute time period.

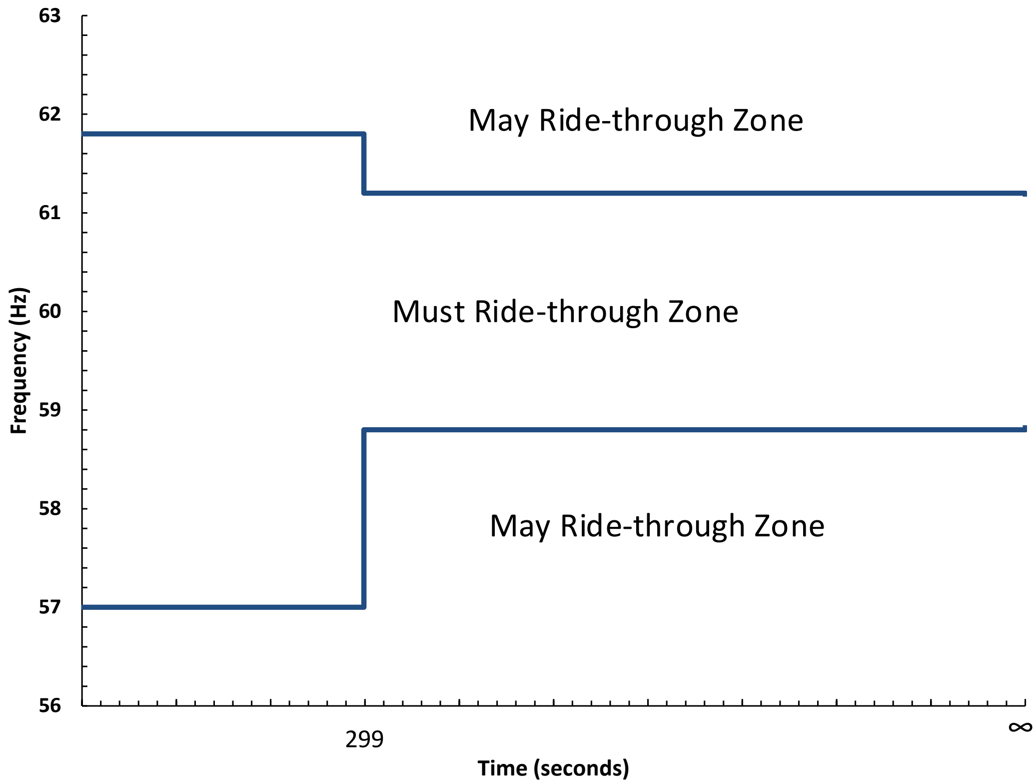

Figure 1: PRC-029 Frequency Ride-through Requirements

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit B

Implementation Plan

Implementation Plan

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
Reliability Standards PRC-024-4 and PRC-029-1

Applicable Standard(s)

- PRC-024-4 – Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and Type 2 Wind Resources, and Synchronous Condensers
- PRC-029-1 – Frequency and Voltage Ride-through Requirements for Inverter-based Generating Resources

Requested Retirement(s)

- PRC-024-3 Frequency and Voltage Protection Settings for Generating Resources

Prerequisite Standard(s)

- None

Applicable Entities

- See subject Reliability Standards.

New Terms in the NERC Glossary of Terms

This section includes all newly defined, revised, or retired terms used or eliminated in the NERC Reliability Standard. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Proposed New Definition(s):
Ride-through: The plant/facility remains connected and continues to operate through voltage or frequency system disturbances.

Background

The purpose of Project 2020-02 is to modify Reliability Standard PRC-024-3 or replace it with a performance-based Ride-through standard that ensures generators remain connected to the Bulk Power System (BPS) during system disturbances. Specifically, the project focuses on using disturbance monitoring data to substantiate inverter-based resource (IBR) ride-through performance during grid disturbances. The project also ensures associated generators that fail to Ride-through system events are addressed with a corrective action plan (if possible) and reported to necessary entities for situational awareness.

The purpose for this project is based on the culmination of multiple analyses conducted by the ERO Enterprise regarding widespread IBR tripping events. Furthermore, the NERC Inverter-Based Resource Performance Subcommittee[1] has developed comprehensive recommendations for improved performance of IBRs, including the recommendation to develop comprehensive ride-through requirements.

In October 2023, FERC issued Order No. 901[2] which directs the development of new or modified Reliability Standards that include new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. In January 2024, NERC submitted a filing to FERC outlining a comprehensive work plan to address the directives within Order No. 901.[3] Within the work plan, NERC identified three active Standards Development projects that would need to be filed for regulatory approval with FERC by November 4, 2024. These projects include **2020-02 Modifications to PRC-024 (Generator Ride-through)**[4], **2021-04 Modifications to PRC-002-2**[5], and **2023-02 Analysis and Mitigation of BES Inverter-based Resource Performance Issues**[6].

Project 2020-02

Proposed Reliability Standard PRC-029-1 is a new Reliability Standard that includes Ride-through requirements and performance requirements for IBRs. The scope of this project was adjusted to align with associated regulatory directives from FERC Order No. 901 and the scope of the other projects related to "Milestone 2" of the NERC work plan. The components of this project's Standard Authorization Request (SAR) that related to the inclusions of new data recording requirements are covered in Project 2021-04 and the proposed new PRC-028-1 Reliability Standard. Components of this project's SAR that relate to analytics and corrective actions plans are covered in Project 2023-02 and the proposed new PRC-030-1 Reliability Standard.

PRC-029-1 includes requirements for Generator Owner IBR to continue to inject current and perform voltage support during a BPS disturbance. The standard also specifically requires Generator Owner IBR to prohibit momentary cessation in the no-trip zone during disturbances.

PRC-024-4 includes modifications to revise applicable facility types to remove IBR, retain type 1 and type 2 wind, and to include synchronous condensers.

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[1] See documents at the NERC IRPS website: https://www.nerc.com/comm/RSTC/Pages/IRPS.aspx and the previous Inverter-Based Resource Performance Working Group website https://www.nerc.com/comm/RSTC/Pages/IRPWG.aspx

[2] See FERC Order 901, Docket No. RM22-12-000; https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false; October 19, 2023

[3] See INFORMATIONAL FILING OF THE NORTH AMERICAN RELIABILITY CORPORATION REGARDING THE DEVELOPMENT OF RELIABILITY STANDARDS RESPONSIVE TO ORDER NO. 901 https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/NERC%20Compliance%20Filing%20Order%20No%20901%20Work%20Plan_packaged%20-%20public%20label.pdf; January 17, 2024

[4] See NERC Standards Development Project page for Project 2002-02; https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx

[5] See NERC Standards Development Project page for Project 2021-04; https://www.nerc.com/pa/Stand/Pages/Project-2021-04-Modifications-to-PRC-002-2.aspx

[6] See NERC Standards Development Project page for Project 2023-02; https://www.nerc.com/pa/Stand/Pages/Project-2023-02-Performance-of-IBRs.aspx

General Considerations

This implementation plan recognizes the urgent need for Reliability Standards to address IBR ride through performance, as demonstrated by multiple event reports of the last decade, while providing a reasonable period of time for entities to develop the necessary procedures and change their protection and control settings to meet the new requirements. The ERO Enterprise acknowledges that there are IBRs currently in operation and unable to meet voltage Ride-through requirements due to their inability to modify their coordinated protection and control settings. Consistent with FERC Order No. 901, a limited and documented exemption process for those IBR is appropriate and included within this Implementation Plan. Other NERC Standards Development projects will be pursued to address ongoing identification and mitigation of any potential reliability impacts to the BPS for such exemptions.

This implementation plan also recognizes that certain requirements (Requirements R1, R2, and R3) call for entities to "ensure the design and operation" of their IBR units meets certain criteria. Design elements may be implemented more expeditiously than operation requirements; the latter of which will require entities to show compliance through use of actual disturbance monitoring data. Therefore, this implementation plan provides staggered timeframes by which entities shall first ensure the design of their IBR units meets the criteria (12 months following regulatory approval). Subsequent compliance with the "operation" elements of these requirements shall become due as entities install disturbance monitoring equipment on each applicable IBR in accordance with the implementation plan for proposed Reliability Standard PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-based Resources.

The ERO Enterprise acknowledges that Generator Owners and Generator Operators owning or operating Bulk Power System connected IBRs that do not meet NERC's current definition of Bulk Electric System ("BES") will be registered no later than May 2026 in accordance with the IBR Registration proceeding in FERC Docket No. RR24-2. To ensure an orderly registration and compliance process for these entities, as well as fairness and consistency in the standard's application among similar asset types, this implementation plan provides additional time for both new and existing registered entities to come into compliance with Reliability Standard PRC-029-1's requirements for their applicable IBRs not meeting the BES definition. In so doing, this implementation plan advances an orderly process for new registrants while allowing existing entities to focus their immediate efforts on their assets posing the highest risk to the reliable operation of the Bulk Power System.

Effective Date and Phased-in Compliance Dates

The effective dates for the proposed Reliability Standards are provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance dates for those particular sections represent the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

PRC-024-4

Where approval by an applicable governmental authority is required, Reliability Standard PRC-024-4 shall become effective on the first day of the first calendar quarter that is twelve months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the Reliability Standard PRC-024-4 shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

PRC-029-1 and definition of Ride-through
Where approval by an applicable governmental authority is required, Reliability Standard PRC-029-1 and the definition of Ride-through shall become effective on the first day of the first calendar quarter that is twelve months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the Reliability Standard PRC-029-1 and the definition of Ride-through shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

PRC-029-1 Phased-in Compliance Dates

Requirements R1, R2, and R3

Capability-Based Elements

Bulk Electric System IBRs
Entities shall comply with the portion of Requirements R1, R2, and R3 relating to the **design** of their BES IBRs to meet the requirements by the effective date of the standard.

Applicable Non-BES IBRs[7]
Entities shall not be required to comply with Requirements R1, R2, and R3 relating to the **design** of their applicable non-BES IBRs until the later of: (1) January 1, 2027; or (2) the effective date of the standard.

Performance-Based Elements (all applicable IBRs)
Entities shall not be required to comply with the portion of Requirements R1, R2, and R3 relating to the **operation** of IBRs to meet the requirements until the entity has established the required

[7] The standard defines such as IBRs as "Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV."

disturbance monitoring equipment capabilities for those IBRs in accordance with the implementation plan for Reliability Standard PRC-028-1.

Requirement R4

Bulk Electric System IBRs
Entities shall comply with Requirement R4 for their BES IBRs by the effective date of the standard.

Applicable Non-BES IBRs
Entities shall not be required to comply with Requirement R4 or their non-BES IBRs until the later of: (1) January 1, 2027; or (2) the effective date of the standard.

Retirement Date

PRC-024-3

Reliability Standard PRC-024-3 shall be retired immediately prior to the effective date of Reliability Standards PRC-024-4 and PRC-029-1 in the particular jurisdiction in which the revised standard is becoming effective.

Equipment Limitations and Process for Requirement R4

Consistent with FERC Order No. 901, a limited and documented exemption for some legacy IBR with certain documented equipment limitations are acceptable. Per the Order, these IBRs are

> "…typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements."[8]

To ensure compliance with Requirement R4 and alignment with FERC Order No. 901, only those IBR that are in operation as of the effective date of PRC-029-1 may be considered for potential exemption. Further, only those IBR that are unable to meet ride-through requirements due to their inability to modify their coordinated protection and control settings may be considered for potential exemption.

[8] Order No. 901 at p. 193.

Exhibit C

Order No. 672 Criteria

EXHIBIT C

Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria.

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]

The Proposed Reliability Standards PRC-029-1 - Frequency and Voltage Ride-through Requirements for Inverter-based Resources and Proposed Reliability Standard PRC-024-4 – Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and 2 Wind Plants, and Synchronous Condensers would advance the reliability of the Bulk-Power System ("BPS") by ensuring applicable BPS connected resources would Ride-through system disturbances and avoid the negative reliability impacts associated with unnecessary tripping and momentary cessation.

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006) [hereinafter Order No. 672].

[2] *See* Order No. 672, *supra* note 1, at P 321 ("The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.").

See Order No. 672, *supra* note 1, at P 324 ("The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.").

Proposed Reliability Standards PRC-029-1 would require Generator Owners of Inverter-Based Resources ("IBR") to Ride-through voltage and frequency system disturbances with capability and performance-based requirements. Specifically, Reliability Standard PRC-029-1 would include requirements for Generator Owners to: (1) be able to properly Ride-through system disturbances; (2) comply with applicable voltage and frequency Ride-through criteria to prevent the unnecessary tripping and momentary cessation of current due to phase lock loop loss of synchronism; and (3) ensure that post-disturbance ramp rates return to pre-disturbance levels.

Proposed Reliability Standard PRC-024-4 contains revisions to apply only to synchronous generators, synchronous condensers, and type 1 and type 2 wind units. Proposed Reliability Standard PRC-024-4 would continue to address frequency and voltage protection setting ranges, but for synchronous units, type 1 and type 2 wind, and synchronous condensers only as IBRs are now being addressed in proposed PRC-029-1. The revised standard applicability is supported by the different natures of synchronous and IBR generation resources, including their risks, performance, and equipment capabilities. Synchronous units do not require performance-based requirements to Ride-through disturbances and type 1 and 2 wind units operate as asynchronous generating resources and do not have modern controllers capable of riding through system events.

Ensuring fault ride-through capability enables dynamic reactive power support, frequency response, and other services. The unexpected loss of widespread IBRs failing to Ride-through poses a significant risk to BPS reliability and is well documented in multiple disturbance reports and highlighted in Order No. 901.

2. Proposed Reliability Standards must be applicable only to users, owners, and operators of the bulk power system, and must be clear and unambiguous as to what

is required and who is required to comply.[3]

The proposed Reliability Standards are clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. Proposed Reliability Standard PRC-029-1 would apply to Generator Owners owning IBRs that either meet the NERC Bulk Electric System definition or Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Proposed Reliability Standard PRC-024-4 would apply to synchronous generators, synchronous condensers, and type 1 and type 2 wind units.

The proposed Reliability Standards clearly articulate the actions that applicable entities must take to comply with the standards.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment, as discussed further in **Exhibit F**. The assignment of the severity level for each VSL is consistent with the corresponding requirement, and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar

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[3] *See* Order No. 672, *supra* note 1, at P 322 ("The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.").

See Order No. 672, *supra* note 1, at P 325 ("The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.").

[4] *See* Order No. 672, *supra* note 1, at P 326 ("The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.").

violations. For these reasons, the proposed Reliability Standards include clear and understandable consequences in accordance with Order No. 672.

4. A proposed Reliability Standard must identify clear and objective criteria or measures for compliance, so that it can be enforced in a consistent and non-preferential manner.[5]

The proposed Reliability Standards contain measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures help provide clarity regarding how the requirements would be enforced and help ensure that the requirements would be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently, but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]

The proposed Reliability Standards achieve their reliability goals effectively and efficiently in accordance with Order No. 672. Proposed Reliability Standard PRC-029-1 would provide robust and technically justified requirements for Generator Owners of IBRs to Ride-through system disturbances and return post-disturbance ramp rates to pre-disturbance levels. Proposed Reliability Standard PRC-029-1 focuses on addressing the important reliability issue of IBR ride-through performance through capability and performance-based requirements for IBRs.

In drafting proposed Reliability Standard PRC-029-1, the drafting team determined that it was necessary to include provisions allowing an exemptions from the Ride-through performance criteria for legacy IBRs because of the hardware limitations associated with those facilities.

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5 *See* Order No. 672, *supra* note 1, at P 327 ("There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.").

6 *See* Order No. 672, *supra* note 1, at P 328 ("The proposed Reliability Standard does not necessarily have to reflect the optimal method, or 'best practice,' for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.").

Specifically, it was determined that the anticipated difficulty of Generator Owners having to wholesale retrofit and redesign legacy facilities currently in operation to meet the requirements of the proposed standard would be unreasonable and unduly burdensome, and it could lead to undesirable impacts on reliability. This exemption is limited to legacy units and only for those criteria for which the hardware limitation exists.

Proposed Reliability Standard PRC-024-4, which is only minimally revised for applicability, would continue to achieve its reliability goals effectively and efficiently for the facilities to which it applies.

6. Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[7]

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. In accordance with the Commission's direction in Order No. 901, proposed Reliability Standard PRC-029-1 reflects a measured and reasoned consideration of the need for IBRs to Ride-through system disturbances, balanced against the implementation burden on entities. Proposed Reliability Standard PRC-029-1 would advance the reliability of the BPS by establishing frequency and voltage Ride-through performance criteria for IBRs to prevent unnecessary tripping or momentary cessation of current injection. Proposed Reliability Standard PRC-024-4 is only minimally revised to limit its applicability for frequency and voltage protection setting ranges to synchronous units, type 1 and type 2 wind units, and synchronous condensers.

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[7] *See* Order No. 672, *supra* note 1, at P 329 ("The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice—the so-called 'lowest common denominator'—if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.").

See Order No. 672, *supra* note 1, at P 330 ("A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed

7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[8]

The proposed Reliability Standards would apply consistently throughout North America and would not favor one geographic area or regional model. While the penetration of IBRs may vary by region, proposed Reliability Standard PRC-029-1 would apply to all IBRs due to the reliability risk associated with IBRs failing to Ride-through system disturbances when they are expected to perform. Proposed Reliability Standard PRC-024-4 would continue to apply across North America without favoring any one geographic area or regional model.

Reliability Standard. However, the ERO should not propose a 'lowest common denominator' Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.").

[8] *See* Order No. 672, *supra* note 1, at P 331 ("A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.").

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]

The proposed Reliability Standards would have no undue negative effect on competition and would not unreasonably restrict the available transmission capacity or limit the use of the BPS in a preferential manner. The reliability need for performance-based requirements for IBRs to Ride-through system disturbances (proposed PRC-029-1) is well documented in multiple disturbance reports and highlighted in Order No. 901. The revised applicability reflected in proposed Reliability Standard PRC-024-4 is supported by the different natures of synchronous and IBR generation resources, including their risks, performance, and equipment capabilities.

9. The implementation time for the proposed Reliability Standards is reasonable.[10]

The implementation plan for the proposed Reliability Standards is just and reasonable and appropriately balances the urgency in the need to implement the standards against the reasonableness of the time allowed for those who must comply to develop necessary procedures or other relevant capability. The proposed implementation plan provides that the proposed Reliability Standards PRC-024-4 and PRC-029-1 shall become effective on the first day of the first calendar quarter that is twelve (12) calendar months after the effective date of the Commission's order approving the proposed Reliability Standards. Currently effective Reliability

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[9] *See* Order No. 672, *supra* note 1, at P 332 ("As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.").

[10] *See* Order No. 672, *supra* note 1, at P 333 ("In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.").

Standard PRC-024-3 would be retired immediately prior to the effective date of proposed Reliability Standard PRC-024-4.

The Implementation Plan for proposed PRC-029-1 provides phased-in compliance dates for both capability and performance-based elements of Requirements R1, R2, and R3 for BES IBRs and non-BES IBRs.

For BES IBRs, the implementation timeframe for capability-based elements is as follows. Generator Owners shall comply with the portion of Requirements R1, R2, and R3 relating to the design of their BES IBRs to meet the requirements by the effective date of the standard. Additionally, the implementation timeframe for the exemption process in Requirement R4 is the effective date of the standard.

For non-BES IBRs, the implementation timeframe for capability-based elements is as follows. Generator Owners shall comply with the portion of Requirements R1, R2, and R3 relating to the design of their applicable non-BES IBRs until the later of: (1) January 1, 2027; or (2) the effective date of the standard. Additionally, the implementation timeframe for the exemption process in Requirement R4 is the later of: (1) January 1, 2027; or (2) the effective date of the standard.

For all IBRs, the implementation timeframe for performance-based elements is as follows. Generator Owners shall not be required to comply with the portion of Requirements R1, R2, and R3 relating to the operation of IBRs to meet the requirements until the entity has established the required disturbance monitoring equipment capabilities for those IBRs in accordance with the implementation plan for proposed Reliability Standard PRC-028-1.[11] Under that plan, Generator

[11] The proposed implementation plan for proposed Reliability Standards PRC-028-1 and PRC-002-5 provides that the proposed standards would become effective the first calendar quarter following regulatory approval.

Owners will follow a phased-in compliance timeline with requirements to establish disturbance monitoring capabilities fully implemented by January 1, 2030.

This Implementation Plan recognizes the need for this phased in compliance timeline so entities can establish disturbance monitoring capabilities before having to comply with the performance-based elements of proposed Reliability Standard PRC-029-1. Further, Generator Owners and Generator Operators owning or operating BPS connected IBRs that do not meet NERC's current definition of BES will be registered no later than May 2026 in accordance with the IBR Registration proceeding in FERC Docket No. RR24-2. To ensure an orderly registration and compliance process for these entities, as well as fairness and consistency in the standard's application among similar asset types, the proposed Implementation Plan provides additional time for both new and existing registered entities to come into compliance with new IBR Ride-through requirements for their applicable IBRs not meeting the BES definition. In so doing, this Implementation Plan advances an orderly process for new registrants while allowing existing entities to focus their immediate efforts on their assets posing the highest risk to the reliable operation of the BPS.

Implementation of PRC-028-1 would then follow a phased-in compliance timeline, ending by 2030. The relevant dates under that plan are as follows:

BES IBRs: Generator Owners shall comply with requirements to establish disturbance monitoring data recording capabilities for 50% of their existing BES IBRs (i.e. in commercial operation on or before the effective date) within three calendar years of the effective date of PRC-029-1, and 100% of their BES IBRs by January 1, 2030. If a Generator Owner has only one such BES IBR, it shall comply within three calendar years. For new BES IBRs, Generator Owners shall comply within 15 calendar months following the effective date of the standard or by the commercial operation date, whichever is later.

Non-BES IBRs: Generator Owners shall comply with requirements to establish disturbance monitoring data recording capabilities for 100% of those non-BES IBRs in commercial operation prior to May 15, 2026 by no later than January 1, 2030. Generator Owners shall comply with for their new non-BES IBRs within 15 calendar months following the effective date of the standard or by the commercial operation date, whichever is later.

Additional information is available in Section VIII and Exhibit B to NERC's Petition for Approval of Proposed Disturbance Monitoring Reliability Standards PRC-028-1 and PRC-002-5 (Nov. 4, 2024).

This phased in implementation plan is consistent with Order No. 672 and complies with FERC's directive in Order No. 901 that NERC "ensure that the associated implementation plans sequentially stagger the effective and enforceable dates to ensure an orderly industry transition for complying with the IBR directives in this final rule prior to [2030]."[12]

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[13]

The proposed Reliability Standards were developed in accordance with NERC's Commission-approved processes for developing and approving Reliability Standards. **Exhibit G** includes a summary of the Reliability Standards development proceedings, and details the processes followed to develop the proposed Reliability Standards. These processes included, among other things, comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the standard drafting team were properly noticed and open to the public.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[14]

NERC has identified no competing public interests regarding the request for approval of this proposed Reliability Standards. No comments were received that indicated that the proposed Reliability Standards conflict with other vital public interests.

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[12] Reliability Standards to Address Inverter-Based Resources, Order No 901, 185 FERC ¶ 61,042 (2023) at P 226.

[13] *See* Order No. 672, *supra* note 1, at P 334 ("Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission.").

[14] *See* Order No. 672, *supra* note 1, at P 335 ("Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.").

12. Proposed Reliability Standards must consider any other appropriate factors.[15]

No other negative factors relevant to whether the proposed Reliability Standards are just and reasonable were identified.

[15] *See* Order No. 672, *supra* note 1, at P 323 ("In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.").

NORTH AMERICAN ELECTRIC
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Exhibit D

Consideration of Directives

Standards Development Consideration of Directives from FERC Order 901

Background

The Federal Energy Regulatory Commission (FERC) issued Order No. 901 on October 19, 2023, which includes directives on new or modified NERC Reliability Standard projects. Order No. 901 addresses a wide spectrum of reliability risks to the grid from the application of inverter-based resources (IBR); including both utility scale and behind the-meter or distributed energy resources. Within the Order, are four milestones that include sets of directives to NERC. The first milestone was achieved on January 17, 2024 as NERC filed its initial work plan to address all aspects of Order No. 901 throughout the next three years.[1] The filed work plan includes extensive detail on Standards Development approach and next steps to accomplish the suite of directives addressing IBR. The work plan was intended to be an initial roadmap to guide development for each of the Reliability Standards Projects identified as a 901-related project.

This document includes specifics for how each directive assigned to Project 2020-02 Modifications to PRC-024 (Generator Ride-through) drafting team have been addressed.

Resources

[FERC Order No. 901 – Final Rule Reliability Standards to Address Inverter-Based Resources](#)
[NERC Mapping Document for FERC Order 901 Directives to Standards Development Projects, Draft SARs, and Pending SARs](#)

[1] INFORMATIONAL FILING OF THE NORTH AMERICAN RELIABILITY CORPORATION REGARDING THE DEVELOPMENT OF RELIABILITY STANDARDS RESPONSIVE TO ORDER NO. 901; 01/17/2024; https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/NERC%20Compliance%20Filing%20Order%20No%20901%20Work%20Plan_packaged%20-%20public%20label.pdf

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
49	190	2	"Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	The new standard PRC-029-1 will require registered generator owners of IBRs to both design and operate their IBR plants to ride through voltage and frequency excursions within "must ride-through zones" according to how these zones are defined in the standard. The must ride-through zones are defined in terms of voltage and frequency magnitude and time duration. Tripping of IBR plants is permitted only outside of the defined must ride-through zones. The voltage and frequency must ride-through zones are based on IEEE 2800-2022 no-trip zones and are established in view of experience with voltage and frequency excursions in planning and operating criteria disturbances, under-frequency load shedding stages, reasonable and practical limits of IBR voltage and frequency tolerances, PRC-024-3 voltage and frequency relay setting graphs, and include adequate margins against worst-case conditions that could be brought about during system disturbances.
50	190	2	"The new or modified Reliability Standards must require registered IBRs to continue to inject current and perform frequency support during a Bulk-Power System disturbance."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	In association with the new PRC-029 standard, a definition of the term *ride-through* is proposed for addition to the NERC Glossary of Terms that essentially states that IBR facilities must remain connected and continue to fulfill their established control and regulation functions (which generally involve exchange of current) in order to qualify as riding through system disturbances. Support of frequency is predicated on, and to a large degree achieved by the riding through of system disturbances. Frequency regulation (or governing) is presently not a continent-wide necessity and not a requirement on individual generating

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
					plants/facilities in NERC standards. RTO/ISO requirements may apply.
51	190	2	"Any new or modified Reliability Standard must also require registered IBR generator owners and operators to prohibit momentary cessation in the no-trip zone during disturbances."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	Momentary cessation, understood as inverter temporary current blocking while still remaining connected, is restricted to only two system conditions: 1) non-fault line switching caused voltage phase angle jumps in excess of 25 degrees that could result in tripping unless the inverter goes into current blocking, and 2) while voltage at the plant-system interface is less than 0.10 per unit during which time it may be difficult or impractical to maintain current exchange.
52	190	2	"NERC must submit new or modified Reliability Standards that establish IBR performance requirements, including requirements addressing frequency and voltage ride through, post-disturbance ramp rates, phase lock loop synchronization, and other known causes of IBR tripping or momentary cessation."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	IBR frequency and voltage ride through requirements are established in the new PRC-029 standard as noted above. A default post-disturbance ramp rate of 1.0 second is specified unless a faster or slower rate is specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator to accommodate specific system post-disturbance recovery needs. Any Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specified ramp rate becomes the standard requirement. Tripping due to phase lock loop loss of synchronism is specifically not permitted within voltage and frequency must ride through zones.
53	193	2	"Therefore, we direct NERC through its standard development process to determine whether the new or modified Reliability	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	Exemption from the voltage must ride-through zone requirement of PRC-029-1 is permitted for IBR plants/facilities that are in service at the enforcement date of the standard. The IBR Generator Owner must document the need for an exemption and the documentation must explain what hardware prevents the IBR

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
			Standards should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements.”		from meeting the requirement and must be specific as to what aspect of the voltage must ride-through zone cannot be met. The Compliance Enforcement Authority checks that all aspects of the documentation specified in the standard have been provided by the GO and the GO is required to supply further information on the need for and the nature of the exemption if requested by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator. The implementation plan provides a 12-month time window for exemption requests to be submitted following the enforcement date. Following the 12-month window, further exemption requests will either not be accepted or could be considered an admission of non-compliance.
54	193	2	“Further, we direct NERC to ensure that any such exemption would be applicable for only existing equipment that is unable to meet voltage ride-through performance. When such existing equipment is replaced, the exemption would no longer apply, and the new equipment must comply with the appropriate IBR performance requirements specified in the Reliability Standards (e.g., voltage and frequency ride	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	The exemption provision of PRC-029-1 is available only for IBR plants/facilities that are in service at the enforcement date as noted above. The exemption provision also stipulates that once the plant/facility hardware causing the inability to comply with the voltage must ride-through requirement is replaced, the exemption is withdrawn (“no longer applies”).

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			through, phase lock loop, ramp rates, etc.)."		
55	193	2	"Finally, we direct NERC, through its standard development process, to require the limited and documented exemption list (i.e., IBR generator owner and operator exemptions) to be communicated with their respective Bulk-Power System planners and operators (e.g., the IBR generator owner's or operator's planning coordinator, transmission planner, reliability coordinator, transmission operator, and balancing authority)."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	The exemption provision of PRC-029-1 requires an IBR Generator Owner to supply its exemption request documentation to its Transmission Planner, Planning Coordinator, Reliability Coordinator, and Transmission Operator within the 12-month window following the enforcement date as noted above.

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56	199	2	"Pursuant to section 215(d)(5) of the FPA, we modify the NOPR proposal. To the extent NERC determines that a limited and documented exemption for those registered IBRs currently in operation and unable to meet voltage ride-through requirements is appropriate due to their inability to modify their coordinated protection and control settings, we direct NERC to develop new or modified Reliability Standards to mitigate the reliability impacts to the Bulk-Power System of such an exemption."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	Mitigation of the reliability impacts of voltage must ride-through exemptions are existing NERC standard responsibilities of Transmission Planners, Planning Coordinators, Reliability Coordinators, and Transmission Operators under TPL, IRO, TOP, and other standards. These entities may need to restrict the operation of exempted IBRs where and when their tripping may result in detrimental reliability impacts.
57	208	2	"Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop and submit to the Commission for approval new or modified Reliability Standards that require post-disturbance ramp rates for registered IBRs to be unrestricted and not	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	As indicated above, a default post-disturbance ramp rate of 1.0 second is specified unless a faster or slower rate is specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator to accommodate specific system post-disturbance recovery needs. Any Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specified ramp rate becomes the standard requirement.

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			programmed to artificially interfere with the resource returning to a pre-disturbance output level in a quick and stable manner after a Bulk-Power System."		
59	209	2	"We direct NERC to submit to the Commission for approval new or modified Reliability Standards that would require registered IBRs to ride through any conditions not addressed by the proposed new or modified Reliability Standards that address frequency or voltage ride through, including phase lock loop loss of synchronism."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	Phase lock loop loss of synchronism is not allowed as a cause of tripping while voltage remains within the must ride-through zone unless there are phase jumps more than 25 degrees caused by non-fault switching events. A footnote under R1 also specifically states that phase lock loop loss of synchronism as not a permissible condition for tripping while voltage remains within the must ride-through zone.
60	209	2	"The proposed new or modified Reliability Standards must require registered IBRs to ride through momentary loss of synchronism during Bulk-Power System disturbances and require registered IBRs to continue to inject current into the Bulk-	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	As indicated above, tripping due to phase lock loop loss of synchronism is specifically not permitted within voltage and frequency must ride-through zones. The requirement to return to pre-disturbance power also includes a provision for return to "available active power" to allow for "changes of facility active power output attributed to factors such as weather patterns, change of wind, and change in irradiance," but "changes of facility active power attributed to IBR tripping in

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
			Power System at pre-disturbance levels during a disturbance, consistent with the IBR Interconnection Requirements Guideline and Canyon 2 Fire Event Report recommendations."		whole or part" are not permitted. Injecting current at pre-disturbance levels during a disturbance is not always practical or desirable. PRC-029-1 R2 specifies IBR required active and reactive power performance during voltage disturbances.
61	209	2	"Related to ACP/SEIA's comment recommending to revise the directive to require generators to maintain synchronism where possible and continue to inject current to support system stability, we direct NERC, through its standard development process, to consider whether there are conditions that may limit generators to maintain synchronism."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	IBRs are non-synchronous but can exhibit forms of instability other than loss of synchronism. System stability is a shared responsibility of Transmission Planners, Planning Coordinators, Reliability Coordinators, and Transmission Operators. IBR generation levels may need to be restricted by these entities to maintain system stability including IBR stability.
63A	226	2	"Further, we believe that there is a need to have all of the directed Reliability Standards effective and enforceable well in advance of 2030 and direct NERC to ensure that the associated implementation plans	Each of the identified Reliability Standards Projects in Milestone 2 will include implementation plans that assure	The PRC-029-1 implementation is a staggered implementation beginning twelve months following governmental approval with enforcement of all provisions within the twelve months following approval except as necessary to coordinate with the PRC-028-1 implementation plan that extends to 2030.

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			sequentially stagger the effective and enforceable dates to ensure an orderly industry transition for complying with the IBR directives in this final rule prior to that date."	all new or modified Reliability Standards are effective and enforceable before 2030.	

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Exhibit E

Technical Rationale

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Exhibit E-1

Technical Rationale
PRC-024-4

Technical Rationale

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

PRC-024-4 – Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and 2 Wind Plants, and Synchronous Condensers

General Rationale

The drafting team proposes to modify PRC-024-3 to retain the Reliability Standard as a protection-based standard with applicability to only synchronous generators, synchronous condensers, and type 1 and 2 wind plants. This proposal is a consequence of both the different natures of synchronous and inverter-based generation resources and several recent events exhibiting significant IBR ride-through deficiencies. The behavior of rotating synchronous generators during faults and other disturbances on the transmission system is well established and understood in comparison to IBR generation. The disturbance ride-through vulnerabilities of synchronous generators are pole slipping instability and undervoltage dropout of critical plant auxiliary equipment, leading to tripping of a generator. Pole slipping (or loss of synchronism) can be managed by active power dispatch constraints or stability System Operating Limits, and is outside the scope of Project 2020-02. Undervoltage dropout of critical auxiliary equipment is also outside the scope of Project 2020-02 because of complexities associated with auxiliary systems and how such equipment behaves under low voltage conditions. The Project 2020-02 Standard Authorization Request (SAR) notes that auxiliary equipment has not posed a ride-through risk and the SAR specifically excludes modifications in PRC-024-3 for auxiliary equipment.

Over-frequency protection, under-frequency protection, over-voltage protection, and under-voltage protection may or may not be applied to synchronous generating units. If applied, settings should be coordinated between the needs of generating unit protection and the no-trip zones within PRC-024-4 attachments. Coordination of generating unit capabilities, voltage regulating controls, and protection is addressed within PRC-019-2. Excitation and governing controls affect synchronous generator ride-through behavior to some degree but because of progressive improvement, standardization, and level of maturity of these controls, they are rarely a cause of unnecessary tripping during disturbances. In addition, there are other existing NERC standards to prevent unnecessary tripping of the generators during a system disturbance such as PRC-025-2 “Generator Relay Loadability” and PRC-026-2 “Relay Performance During Stable Power Swings”. For these reasons, there is no need to impose actual disturbance ride-through requirements on synchronous units but only to include restrictions for frequency and voltage protection setting ranges as maintained in PRC-024-4.

Rationale for Applicability Section (4.0)

Functional Entities (4.1)

The functional entity responsible for setting frequency, voltage, and volts per hertz protection for synchronous generators, type 1 and 2 wind plants, and synchronous condensers is either the Generator Owner ~~(GO)~~ or Transmission Owner ~~(TO)~~. Planning Coordinators ~~(PC)~~ are retained as applicable entities only in the Quebec Interconnection. Modifications are proposed in PRC-024-4 to expand functional entity applicability to include “Transmission Owners that apply protection” because of the inclusion of synchronous condenser applicability in section 4.2.2.

Facilities (4.2)

Applicability Facilities subparts in Section 4.1.1 were modified to restrict PRC-024-4 to synchronous generators and type 1 and 2 wind plants. Section 4.2.2 was added to cover synchronous condensers and associated equipment.

Rationale for Requirements R1 through R4

Modifications were made to Requirements R1, R2, R3, and R4 to include the Transmission Owner as a functional entity applicable to each requirement because of the addition of synchronous condensers.

Modifications were made to Requirements R1, R2, R3, and R4 to include language for type 1 and 2 wind plants and synchronous condensers and to remove language that relates to inverter-based resource (IBR) functionality since IBRs will be addressed in a new standard PRC-029-1.

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Exhibit E-2

Technical Rationale
PRC-029-1

Technical Rationale

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

PRC-029-1 – Frequency and Voltage Ride-through Requirements for Inverter-based Generating Resources

General Rationale

The drafting team has created a new Reliability Standard (PRC-029-1) to address inverter-based resource (IBR) disturbance Ride-through performance criteria. This proposal is a consequence of both the different natures of synchronous and inverter-based generation resources and several recent events exhibiting significant IBR Ride-through deficiencies[1]. The proposed PRC-029-1 aligns with certain Ride-through requirements of IEEE Std 2800™, IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems, primarily for frequency Ride-through, and is structured to follow language from FERC Order No. 901, which states that "NERC has the discretion to consider during its standards development process whether and how to reference IEEE standards in the new or modified Reliability Standards."[2]

The lack of standardization of IBR performance and the software-based nature of the technologies has created reliability challenges associated with the interconnection of IBR facilities to the power grid. The nature of the fast switching of power electronics of IBR generation, IBR's software-based nature, and the electronic interface to the transmission system is such that disturbance Ride-through behavior is largely determined by manufacturer-specific equipment and controls system designs. These controls may be programmed, but also have more restrictive limits on current, both in magnitude and duration. IBR responses to grid disturbances are highly controlled and managed by using fast switching of power electronics devices dependent upon manufacturer specific control system design software that can be programmed in many ways and with various and concurrent Ride-through performance objectives. Rather than attempting to restrict the myriad of control approaches, protections, and settings, it is more straightforward to require Ride-through during defined frequency and voltage excursions.

In contrast to synchronous generation, the need for IBR Ride-through requirements has been heightened by recent events during which IBRs have not met PRC-024-3 frequency and voltage Ride-through expectations, often due to controls and protection only indirectly associated with the system voltage and frequency excursions. In addition to Ride-through, there is the question of what IBRs should be doing as they Ride-through. IBR responses to system disturbances can be beneficial or detrimental to both their own Ride-through and system reliability, often depending on adjustable control settings. Thus, it is essential to set expectations on performance during Ride-through as well as Ride-through capability.

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[1] Event Reports (nerc.com)
[2] P 195, FERC Order No. 901; https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false; October 17, 2023

A further reason for proposing a separate IBR standard is that the inertial and short circuit contributions from IBR are significantly different than synchronous machines. The drafting team thinks that IBRs should Ride through voltage and frequency excursions up to their maximum capability, while using expanded voltage and frequency Ride-through criteria to drive those enhancements. These differences between synchronous machines and IBR contribute to the differences in the frequency and voltage tables and graphs between the PRC-024-4 and PRC-029-1 standards.

The proposed PRC-029-1 must be understood generally as an event-based standard though it is also required to provide evidence of the ability to Ride-through disturbance events by means of dynamic models and simulation results. Compliance with PRC-029-1 is determined chiefly, though not exclusively, from IBR Ride-through performance during transmission system events in the field. An IBR becomes noncompliant with PRC-029-1 when an event in the field occurs that shows that one or more requirements were not satisfied. This intent is clarified by *Operations Assessment* as the Time Horizon designation of requirements R1-R3.

FERC Order No. 901 Directives

PRC-029-1 is proposed in consideration of directives from FERC Order No. 901 that were assigned to the Project 2020-02 drafting team. The following directives were assigned to this drafting team for inclusion in this standards project (paragraph numbers of the FERC Order are included for reference):

- Paragraph 190: “Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults.”
- Paragraph 190: “The new or modified Reliability Standards must require registered IBRs to continue to inject current and perform frequency support during a Bulk-Power System disturbance.”
- Paragraph 190: “Any new or modified Reliability Standard must also require registered IBR generator owners and operators to prohibit momentary cessation in the must Ride-through zone during disturbances.”
- Paragraph 190: “NERC must submit new or modified Reliability Standards that establish IBR performance requirements, including requirements addressing frequency and voltage ride through, post-disturbance ramp rates, phase lock loop synchronization, and other known causes of IBR tripping or momentary cessation.”
- Paragraph 193: “Therefore, we direct NERC through its standard development process to determine whether the new or modified Reliability Standards should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements.”

- Paragraph 193: "Further, we direct NERC to ensure that any such exemption would be applicable for only existing equipment that is unable to meet voltage Ride-through performance. When such existing equipment is replaced, the exemption would no longer apply, and the new equipment must comply with the appropriate IBR performance requirements specified in the Reliability Standards (e.g., voltage and frequency ride through, phase lock loop, ramp rates, etc.)."
- Paragraph 193: "Finally, we direct NERC, through its standard development process, to require the limited and documented exemption list (i.e., IBR generator owner and operator exemptions) to be communicated with their respective Bulk-Power System planners and operators (e.g., the IBR generator owner's or operator's planning coordinator, transmission planner, reliability coordinator, transmission operator, and balancing authority)."
- Paragraph 199: "Pursuant to section 215(d)(5) of the FPA, we modify the NOPR proposal. To the extent NERC determines that a limited and documented exemption for those registered IBRs currently in operation and unable to meet voltage Ride-through requirements is appropriate due to their inability to modify their coordinated protection and control settings, we direct NERC to develop new or modified Reliability Standards to mitigate the reliability impacts to the Bulk-Power System of such an exemption."
- Paragraph 208: "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop and submit to the Commission for approval new or modified Reliability Standards that require post-disturbance ramp rates for registered IBRs to be unrestricted and not programmed to artificially interfere with the resource returning to a pre-disturbance output level in a quick and stable manner after a Bulk-Power System."
- Paragraph 209: "The proposed new or modified Reliability Standards must require registered IBRs to ride through momentary loss of synchronism during Bulk-Power System disturbances and require registered IBRs to continue to inject current into the Bulk-Power System at pre-disturbance levels during a disturbance, consistent with the IBR Interconnection Requirements Guideline and Canyon 2 Fire Event Report recommendations."
- Paragraph 209: "Related to ACP/SEIA's comment recommending to revise the directive to require generators to maintain synchronism where possible and continue to inject current to support system stability, we direct NERC, through its standard development process, to consider whether there are conditions that may limit generators to maintain synchronism."
- Paragraph 209: "We direct NERC to submit to the Commission for approval new or modified Reliability Standards that would require registered IBRs to ride through any conditions not addressed by the proposed new or modified Reliability Standards that address frequency or voltage ride through, including phase lock loop loss of synchronism."
- Paragraph 226: "Further, we believe that there is a need to have all of the directed Reliability Standards effective and enforceable well in advance of 2030 and direct NERC to ensure that the associated implementation plans sequentially stagger the effective and enforceable dates to ensure an orderly industry transition for complying with the IBR directives in this final rule prior to that date." (*pertains to multiple projects*)

Rationale for Applicability Section (4.0)

Functional Entities (4.1)

The functional entity responsible for assuring acceptable Ride-through performance of IBR is the Generator Owner.

Facilities (4.2)

Applicability Facilities include only IBR that also meet NERC registration criteria. Language used within PRC-029-1 applicability only refers to IBR as a whole plant/facility. Consistent with FERC Order No. 901, IBR performance is based on the overall IBR plant and disturbance monitoring equipment requirements established under the proposed PRC-028-1. Requirements within PRC-029-1 do not apply to individual inverter units or measurements taken at individual inverter unit terminals.

Rationale for Requirement R1

The objective of Requirement R1 is to ensure that all applicable IBRs will Ride-through grid voltage disturbances consistent with the must Ride-through zone and operation regions specified in **Attachment 1**. IBRs must be able to demonstrate Ride-through performance, that they remain electrically connected, i.e., shall not trip, and continue to exchange current, i.e., shall not enter momentary cessation.

The drafting team determined that the definition of “must Ride-through zones” and “operation regions” should be consistent with those terms as used within IEEE 2800-2022. Additionally, the team determined that the voltage thresholds of each operation region should be based on measurements taken on the high-side of the main power transformer in PRC-029-1, also consistent with IEEE 2800-2022.

Battery Energy Storage Systems (BESS) units also must comply with Requirement R1 in all operating modes including charging, discharging, and idle (energized, but not charging or discharging). A BESS in idle mode must be capable of responding to system voltage and frequency excursions as it does in charging or discharging modes.

Exceptions to **Attachment 1** performance criteria are allowable when 1) an IBR needs to trip to clear a fault, 2) voltage at the high-side of the main power transformer goes outside an accepted and a documented hardware equipment limitation established in accordance with Requirement R4, 3) instantaneous positive sequence voltage phase angle jumps more than 25 electrical degrees at the high-side of the main power transformer initiated by a non-fault switching events occur on the transmission system, or 4) volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

When a grid disturbance occurs, such as a close-in fault or a relatively large switching event, the grid voltage may experience a rapid phase angle shift. In such cases, the phase displacement $\Delta\theta$ can be large enough to pose challenges for the phase lock loop (PLL) to track the terminal voltage, cause control instability within the inverter, such as the inner current control loop or the DC link control loop, and even lead to tripping of the inverter due to the malfunction of the controls.

Since phase angle jumps are common occurrences on the BPS, this standard requires the IBR to be designed and operated to Ride-through a minimum phase angle jump of 25 electrical degrees. This is a typical value and aligns with the requirement in IEEE 2800-2022.

Some IBR equipment has PLL loss of synchronism protection, referring to a protective function that operates when the angle displacement $\Delta\theta$ exceeds a threshold for a predetermined period of time (on the order of a couple of milliseconds). Historically, this protection has been used by some inverter manufacturers, especially for inverters in distribution systems. For the IBR connected to the BPS, this protection function should be disabled. If it is enabled, the phase angle jump protection setting should be configured such that the IBR shall only trip to prevent equipment damage.

Rationale for Requirement R2

In addition to having minimum voltage Ride-through capability specified in Requirement R1, all applicable IBRs are also required to adhere to certain voltage Ride-through performance criteria during system disturbances. Acceptable performance criteria depend on the operation region that an IBR is presently in or when in transition from one operation region to another operation region. Requirement R2 includes specific performance criteria and is needed to assure consistent IBR performance within and each operation region in **Attachment 1** and when in transition between regions.

Rationale for Requirement R2.1

This subpart of Requirement R2 ensures that when the voltage at the high-side of the main power transformer (MPT) recovers to the continuous operation region from either the mandatory operation region or the permissive operation region, an IBR delivers the pre-disturbance level of Real Power or available Real Power, whichever is less. Available Real Power allows for changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes attributed to IBR tripping in whole or part. This requires an IBR to exit the “High Voltage Ride Through (HVRT)” or “Low Voltage Ridge Through (LVRT)” modes properly such that it does not cause reduction in the Real Power when the high-side of MPT voltage recovers to within the continuous operation region.

When the voltage at the high-side of the MPT is greater than 0.90 per-unit and less than 0.95 per-unit, IBRs are expected to exit the LVRT mode and come back to “normal operating mode”. If an IBR has a default total current limit of 1.0 per-unit, the apparent power production of an IBR will be limited below 1.0 per-unit (e.g., the per-unit value of IBR terminal voltage). In such case, the IBR needs to configure a preference setting, either to maintain pre-disturbance Real Power or maximize the Reactive Power in order to further help with voltage recovery, or according to requirements specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Rationale for Requirement R2.2

This subpart of Requirement R2 ensures that when the voltage at the high-side of the MPT is within the mandatory operation region, IBRs inject or absorb reactive current proportional to the level of terminal voltage deviations they measure. IBRs shall follow Transmission Planner, Planning Coordinator, Reliability

Coordinator, or Transmission Operator specified certain magnitude of Reactive Power response to voltage changes, if available.

By default, reactive current prioritization shall be configured unless Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires Real Power priority.

Rationale for Requirement R2.3

This subpart of Requirement R2 ensures that when the voltage at the high-side of the MPT is within the permissive operation region, IBRs continue to Ride-through, though they are briefly allowed to enter the current block mode if necessary to avoid tripping off from the grid. The drafting team takes into consideration the physical operational capability of the power electronics devices under such low voltage conditions. However, the IBR facility shall restart current exchange in less than or equal to five cycles of positive sequence voltage returning to the continuous operation region or mandatory operation region. If the interconnecting entity has performance requirements that are more stringent than the standard, the Generator Owner should follow the requirements set by the interconnecting entity.

Rationale for Requirement R2.4

This subpart of Requirement R2 ensures when a fault is cleared on the transmission system, the voltage regulators of connected IBRs must adjust the reactive current injection to restore the transmission system voltage to the pre-disturbance voltage as defined by the automatic voltage regulator (AVR) setpoint. The drafting team acknowledges that tuning of the AVR requires a balance between multiple competing physical factors, e.g., rise time, overshoot, and transient stability. However, it is anticipated that IBR controls will be tuned to allow for a stable post-disturbance voltage recovery without causing excessive overshoot or undershoot of the setpoint. When such overshoots do occur, they must not exceed the magnitude and duration of the applicable table given in **Attachment 1**. Furthermore, this standard anticipates that control system tuning to prevent such over/under voltages will focus on the speed at which the controller responds to setpoint changes rather than on the magnitude of the reactive current response. For example, reductions in k-factor to prevent over/under voltages should only be considered as a last resort.

Rationale for Requirement R2.5

This subpart of Requirement R2 ensures that the IBR returns to effective pre-disturbance operation unless otherwise specified or needed by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Rationale for Requirement R3

The objective of Requirement R3 is to ensure that IBRs Ride-through frequency excursion events with magnitude and time durations as defined in Attachment 2.

Grid frequency reflects the balance of system generation and load. A system event that causes a generation/load imbalance will cause system frequency to deviate from nominal. The system may experience an over-frequency event (in the case of more generation than load) or an under-frequency event (in the case of less generation than load). Inertia resists the deviation from nominal frequency, giving the operators additional time to rebalance generation and load. With the current resource mix, system inertia is dependent on the amount of rotating mass connected to the system (i.e., synchronous generators or motors). The larger the system inertia, the slower the system frequency will deviate from the nominal value and the lower the grid Rate Of Change Of Frequency (ROCOF), giving more time to try to rebalance generation and load.

A reduction in system inertia is an inevitable consequence of a power system transiting toward more IBR and less synchronous generators, however the utilization of IBR-specific control features (i.e., advanced control modes and Grid Forming technologies) can provide additional stability benefits to help mitigate the loss of inertia. As discussed in the previous paragraph, less system inertia means the frequency will deviate from the nominal value more quickly during a generation/load imbalance event and will expose the system to a higher ROCOF. A wider frequency Ride-through capability for IBR may be required to avoid the risk of widespread tripping.

When considering an expansion of Ride-through capability, it is important to balance the expansion with the feasibility of producing and installing equipment that can meet the newly proposed criteria. Failure to adequately consider this could result in resource adequacy deficiencies if expanded criteria lead to widespread non-compliance of legacy IBR due to hardware limitations. Further, for newly interconnecting IBR, expanded Ride-through criteria often result in significant design changes that have production time and cost implications. If proposed Ride-through criteria are too stringent and result in costly design changes, those costs could result in a slowing of IBR penetration on the BPS.

For the reasons above, it is imperative that newly created Ride-through criteria are reasonable for both BPS reliability and for the IBR equipment. To date, NERC has analyzed numerous major events including both winter storms Uri and Elliot. No IBR tripped offline for frequency threshold criteria (because the system frequency caused a trip due to exceeding equipment frequency limits) and all frequency-related tripping observed were due to mis-parameterization or the use of instantaneous measurements in protection schemes. Additionally, the deviations in frequency observed during the events listed above did not exceed the PRC-024 criteria. It should be noted that winter storm Uri did produce a frequency excursion extremely close to, and even touching, the criteria in PRC-024.

With no “benchmark events” to inform criteria expansions, studies could be used to assess future BPS needs. These studies would need a detailed list of scenarios, including different IBR penetrations and load levels, and are dependent on the ability to accurately model current and future IBR technologies, including GFM functions. NERC has issued two level 2 alerts related to IBR, one on IBR performance and the second on modeling. These alerts seek to obtain data from IBR while also giving recommendations to mitigate the observed systemic modeling and performance deficiencies of IBR. Given these observed deficiencies and the lack of recently conducted detailed system-wide studies, there is insufficient study-based evidence to inform widely expanded Ride-through criteria.

It is clear however that the performance of the BPS during disturbance will change as the IBR penetration increases. How this performance will change can be predicted with detailed studies, but an incremental approach to expanding Ride-through criteria adds additional stability margin while modeling deficiencies are addressed and detailed studies are conducted.

The frequency Ride-through times and thresholds in IEEE 2800-2022 are more stringent (wider) than those presently in PRC-024-3 and contain continuous operation ranges that exceed the frequency excursions observed during major BPS disturbances. Detailed feedback from original equipment manufacturers (OEM) provides insight that they are already designing IBR equipment that conforms with the criteria in IEEE 2800-2022. For this reason, the frequency Ride-through criteria in the PRC-029 standard are in alignment with those criteria in IEEE 2800-2022, which provides an expansion of Ride-through criteria compared to PRC-024 while also minimizing cost and timeline implications as OEM are already designing conforming equipment.

Requirement R3 does not prescribe specific frequency protection settings for IBR equipment. IBR frequency protection settings should only be set to protect the IBR from damage caused by operation at off-nominal frequency. An IBR owner must ensure that the IBR frequency protection does not prevent an IBR from meeting the R3 Ride-through requirement.

This standard requires that IBRs remain electrically connected and continue to exchange current during a frequency excursion event in which the frequency remains within the must Ride-through zone according to **Attachment 3** and while the absolute ROCOF magnitude is less than or equal to 5 Hz/second. Some IBR controllers and their ability to remain electrically connected and continue to exchange current with the grid are sensitive to ROCOF, particularly auxiliary equipment that are essential for IBR performance, during a frequency excursion event. If needed to maintain the stability of the IBR or prevent equipment damage, the R3 requirement allows the IBR to trip for an absolute ROCOF exceeding 5Hz/sec within the must Ride-through zone of **Attachment 2**. Failure to Ride-through due to ROCOF exceeding 5Hz/sec shall only be allowed during a generator/load imbalance event that causes the frequency to deviate from nominal.

To minimize the misoperation tripping of the IBR on the ROCOF setting, the rate of change of frequency (ROCOF) must be calculated as the average rate of change over multiple calculated system frequencies for some time greater than or equal to 0.1 seconds. The ROCOF calculation is not applicable during the fault occurrence and clearance (i.e., protection should not trip due to any perceived ROCOF during the entire disturbance and recovery period) and should not operate at the onset of a fault, during a fault, or at fault clearance, i.e., it should be disabled during faults. The IBR shall Ride-through any system disturbance while the voltage at the high-side of the main power transformer remains within the must Ride-through zones as specified in **Attachment 1**. The ROCOF measurement should begin after fault clearance and is only applicable for generation/load imbalance disturbances such as a system separation, an island condition, or the loss of a large load or generator.

Rationale for Requirement R4

The objective of Requirement R4 is to ensure legacy IBR (IBR existing as of the enforcement date of PRC-029-1) are able to obtain an exemption to the voltage and frequency Ride-through requirements if hardware replacements or other costly upgrades would be necessary to comply with Requirements R1 through Requirement R3. This provision allows such exemptions as long as such limitations are documented and communicated to the Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator of the respective footprints in which the IBR project is located. The Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator will then need to take the voltage Ride-through limitations into account in planning and operations.

Limitations must not be construed as complete exemptions from the applicable tables, but must be specific as to which voltage or frequency band(s) and associated duration(s) cannot be satisfied or specific as to the number of cumulative voltage deviations within a ten-second time period that the equipment can Ride-through if less than four. Limitation descriptions should identify the specific equipment and explain the characteristic(s) of that equipment that prevent Ride-through. If any equipment limitation is removed or otherwise corrected, it is likewise necessary to communicate to the Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator of this.

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Exhibit F

Analysis of Violation Risk Factors and Violation Severity Levels

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Exhibit F-1

Analysis of Violation Risk Factors and Violation Severity Levels PRC-024-4

Violation Risk Factor and Violation Severity Level Justifications

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
PRC-024-4

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-024-4. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to BulkPower System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to BulkPower System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System. However, violation of a medium risk requirement is unlikely to lead to Bulk- Power System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BulkPower System, or the ability to effectively monitor, control, or restore the BulkPower System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC’s overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.
Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

The VRF did not change from the previously FERC approved PRC-024-3 Reliability Standard.

VSLs for PRC-024-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to set its applicable frequency protection so that it does not trip according to Requirement R1.

VSL Justifications for PRC-024-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement adds a functional entity. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-024-4, Requirement R1	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

The VRF did not change from the previously FERC approved PRC-024-3 Reliability Standard.

VSLs for PRC-024-4, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
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 according to Requirement R2.

VSL Justifications for PRC-024-4, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement adds a functional entity. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-024-4, Requirement R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

The VRF did not change from the previously FERC approved PRC-024-3 Reliability Standard.

VSLs for PRC-024-4, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner or Transmission 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 or Transmission 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 or Transmission 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 or Transmission 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 or Transmission Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.

VSL Justifications for PRC-024-4, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement adds a functional entity. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for PRC-024-4, Requirement R3	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

The VRF did not change from the previously FERC approved PRC-024-3 Reliability Standard.

VSLs for PRC-024-4, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner or Transmission Owner provided its protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner or provided protection settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner or Transmission Owner failed to provide its protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner failed to provide protection settings within 150 calendar days of a written request.

VSL Justifications for PRC-024-4, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement adds a functional entity. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-024-4, Requirement R4	
Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

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Exhibit F-2

Analysis of Violation Risk Factors and Violation Severity Levels PRC-029-1

Violation Risk Factor and Violation Severity Level Justifications

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
PRC-029-1

This document provides the drafting team's (DT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-029-1. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The DT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Power System (BPS) instability, separation, or a cascading sequence of failures, or could place the BPS at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to BPS instability, separation, or a cascading sequence of failures, or could place the BPS at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the BPS, or the ability to effectively monitor and control the BPS. However, violation of a medium risk requirement is unlikely to lead to BPS instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BPS, or the ability to effectively monitor, control, or restore the BPS. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BPS instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the BPS, or the ability to effectively monitor and control the BPS; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BPS, or the ability to effectively monitor, control, or restore the BPS.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the BPS. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BPS:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justifications for PRC-029-1, Requirement R1	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate as applicable generating resources must be able to ride-through system disturbances. Failure to ride-through has been documented in multiple NERC reports leading to exacerbated system conditions, resulting in the electrical disconnecting of additional generation and widespread outages.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Similar requirements in PRC-024-3 are identified as Medium but are based on equipment protection setting documentation rather than actual, recorded performance during a grid disturbance. Therefore, this VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner failed to ensure the design capability of each applicable IBR to Ride-through in accordance with Attachment 1, except for those conditions identified in Requirement R1.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to Ride-through requirements in accordance with Attachment 1, except for those conditions identified in Requirement R1.

VSL Justifications for PRC-029-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R1	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R2	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate as applicable generating resources must be able to ride-through system disturbances. Failure to ride-through has been documented in multiple NERC reports leading to exacerbated system conditions, resulting in the electrical disconnecting of additional generation and widespread outages.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Similar requirements in PRC-024-3 are identified as Medium but are based on equipment protection setting documentation rather than actual, recorded performance during a grid disturbance. Therefore, this VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-029-1, Requirement R2	
Proposed VRF	**High**
Definitions of VRFs	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner failed to ensure the design capability of each applicable IBR to adhere to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.

VSL Justifications for PRC-029-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for PRC-029-1, Requirement R2	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R3	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of High is appropriate that if violated, it would be expected to adversely affect the electrical state or capability of the BPS.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner IBR to ensure the design capability of each applicable IBR to Ride-through in accordance with Attachment 2,	N/A	N/A	The Generator Owner IBR to ensure each applicable IBR adhered to Ride-through requirements in accordance with Attachment 2,

unless a documented hardware limitation exists in accordance with Requirement R4.			unless a documented hardware limitation exists in accordance with Requirement R4.

VSL Justifications for PRC-029-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for PRC-029-1, Requirement R3	
Number of Violations	

VRF Justifications for PRC-029-1, Requirement R4	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate that if violated, it would not be expected to adversely affect the electrical state or capability of the BPS.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of Lower VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a Lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 12 months but less than or equal to 15 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 90 days but less than or equal to 120 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 90 days but less than or equal to 120 days after receiving the acceptance of a hardware limitation by the CEA. OR The Generator Owner with a previously communicated hardware limitation that replaces	The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 120 days but less than or equal to 150 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 120 days but less than or equal to 150 days after receiving the acceptance of a hardware limitation by the CEA. OR The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 120 calendar days but less than or	The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 150 days but less than or equal to 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 150 days but less than or equal to 180 days after receiving the acceptance of a hardware limitation by the CEA. OR The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 150 calendar days but less than or	The Generator Owner failed to document complete information for IBR identified with known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1 or R2. OR The Generator Owner failed to provide a copy to the applicable entities as detailed in Requirement R4.2 within 24 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 180 days after receiving the acceptance of a hardware limitation by the CEA.

VSLs for PRC-029-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and CEA more than 90 calendar days but less than or equal to 120 calendar days after the change to the hardware.	equal to 150 calendar days after the change to the hardware.	equal to 180 calendar days after the change to the hardware.	OR The Generator Owner failed to document complete information for IBR identified with known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1 or R2.

VSL Justifications for PRC-029-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R4	
Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit G

Summary of Development and Complete Record of Development

Summary of Development History

The following is a summary of the development record for proposed Reliability Standards PRC-024-4 and PRC-029-1. Project 2020-02 was originally initiated in 2020 to revise the PRC-024 standard, as well as several other standards, to include all types of dynamic reactive sources and DC transmission systems used to provide Essential Reliability Services to the Bulk Electric System. The scope of Project 2020-02 was adjusted in 2022 to address ride-through performance for generating resources.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team ("SDT") selected to lead each project in accordance with Section 4.3 of the NERC Standard Processes Manual.[2] For this project, the SDT consisted of industry experts, all with a diverse set of experiences. A roster of the Project 2020-02 SDT members is included in **Exhibit H**.

II. Standard Development History

A. Project Initiation

In 2020, NERC initiated Project 2020-02 Transmission Connected Resources to address a Standards Authorization Request ("SAR") submitted by the NERC System Analysis and Modeling Subcommittee ("SAMS") proposing to modify Reliability Standards MOD-025-2, MOD-026-1, MOD-027-1, PRC-019-2 and PRC-024-3. The SAMS developed a white paper to support this

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1 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. § 824(d)(2).

2 The NERC *Standard Processes Manual* is available at https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/SPM_Clean_Mar2019.pdf.

project, addressing deficiencies of reactive power support from nonsynchronous generating resources and transmission-connected dynamic reactive sources.[3]

B. Standard Authorization Request Development

On March 18, 2020, the Standards Committee accepted the SAMS SAR and authorized posting the SAR for a 30-day informal comment period and the solicitation of SAR drafting team members.[4] The informal comment period and the nomination period for a SAR drafting team was extended and was open from March 30, 2020 through May 13, 2020.

C. Supplemental Drafting Team Nominations

Supplemental drafting team nominations were held from April 28, 2021 through May 17, 2021 and from November 19, 2021 – December 20, 2021.[5] The Standards Committee appointed the SAR drafting team on September 23, 2021.[6] Additional SAR drafting team members were appointed on February 16, 2022.[7] Since the original SAR had overlapping Reliability Standards with other projects, the Standards Committee determined that the Project 2020-02 drafting team would focus on revisions to PRC-024 and definitions in the *Glossary of Terms used in NERC Reliability Standards*.

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[3] *See* NERC Standards Committee March 18, 2020 Agenda Package, Item 6, https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC%20Agenda%20Package_March2020.pdf.

[4] NERC, *Meeting Minutes – Standards Committee Meeting* (March 18, 2020), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC_March_Meeting_Minutes_Approved_April_22_2020.pdf.

[5] *See* Exhibit G, Complete Record of Development, at items 10,12.

[6] NERC, *Meeting Minutes – Standards Committee Meeting* (Sept. 23, 2021), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC%20September%20Minutes%20-%20Approved%20October%2020,%202021.pdf.

[7] NERC, *Meeting Minutes – Standards Committee Meeting* (Feb. 16, 2022), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC_February_Meeting_Minutes_Approved_April_20_2022.pdf.

D. Acceptance of Revised SAMS SAR

On April 20, 2022, the Standards Committee accepted the revised SAMS SAR, authorized drafting revisions to the Reliability Standards identified in the SAR, and appointed the Project 2020-02 SAR drafting team as the standard drafting team.

E. Standard Authorization Request Development (Generator Ride-Through)

On April 28, 2022, NERC Staff submitted a Standard Authorization Request seeking to retire Reliability Standard PRC-024-3 and replace it with a performance-based ride-through standard that ensures generators remain connected to the Bulk-Power System during system disturbances. The project name for Project 2020-02 was then was changed to Project 2020-02 Modifications to PRC-024 (Generator Ride-Through). On May 18, 2022, the Standards Committee accepted the Modifications to PRC-024 Ride-through SAR and authorized posting of the SAR for a 45-day formal comment period from May 31, 2022 – July 14, 2022. The Standards Committee also authorized the solicitation of supplemental SDT members.[8]

F. Standard Authorization Request Development (Revised)

On April 19, 2023, the Standards Committee accepted the Modifications to PRC-024 Ride-through SAR as revised by the drafting team, authorized drafting revisions to the Reliability Standards identified in the SAR, and appointed the Project 2020-02 SAR drafting team as the Project 2020-02 standards drafting team.[9]

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8 NERC, *Meeting Minutes – Standards Committee Meeting* (May 18, 2022), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC%20May%20Meeting%20Minutes%20-%20Approved%20June%2015,%202022.pdf.

9 NERC, *Meeting Minutes – Standards Committee Meeting* (Apr. 19, 2023), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/April%20Meeting%20Minutes%20-%20Aprove%20May%2017,%202023.pdf.

G. Issuance of Federal Energy Regulatory Commission Order No. 901

On October 19, 2023, the Commission issued Order No. 901[10] directing NERC to develop new or modified Reliability Standards addressing reliability concerns related to IBRs. Accordingly, proposed Reliability Standards PRC-029-1 and PRC-024-4, related to performance requirements for registered IBRs, were aligned with associated regulatory directives from Order No. 901.

H. Standards Committee Authorizes Procedural Waiver

On December 13, 2023, the Standards Committee authorized a waiver of Sections 4.7, 4.9 and 4.12 of the Standard Processes Manual to reduce the initial formal comment and ballot period for Project 2020-02 from 45 days to as little as 25 days, with ballot pools formed in the first 10 days and initial ballot and non-binding poll of VRFs and VSLs conducted during the last 10 days of the comment period, additional formal comment and ballot period(s) reduced from 45 days to as little as 15 days, with ballot(s) conducted during the last days of the comment period, and final ballot reduced from 10 days to 5 calendar days.[11]

I. First Posting – Comment Period, Initial Ballot, and Non-binding Poll

On March 20, 2024, The Standards Committee authorized initial posting of proposed Reliability Standards PRC-024-4 and PRC-029-1, the associated Implementation Plan and other associated documents for a 25-day formal comment period from March 27, 2024 through April 22, 2024, with a parallel initial ballot and non-binding poll on the Violation Risk Factors ("VSFs") and Violation Severity Levels ("VSLs") held during the last 10 days of the comment period from

10 *Reliability Standards to Address Inverter-Based Resources*, Order No. 901, 185 FERC ¶ 61,042 (2023).

11 Exhibit G, Complete Record of Development at item 24.

April 12, 2024 through April 22, 2024.[12] The initial ballot and non-binding poll results for the proposed Reliability Standards are as follows:

- Proposed Reliability Standard PRC-024-4 received 61.73 percent approval, reaching quorum at 91.51 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 76.51 percent supportive opinions, reaching quorum at 83.07 percent of the ballot pool.[13]
- Proposed Reliability Standard PRC-029-1 received 25.37 percent approval, reaching quorum at 91.01 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 25.15 percent supportive opinions, reaching quorum at 88.45 percent of the ballot pool.[14]
- The Implementation Plan received 37.5 percent approval, reaching quorum at 91.14 percent of the ballot pool.[15]

There were 79 sets of responses, including comments from approximately 180 different individuals and approximately 111 companies, representing all 10 industry segments.[16]

J. Second Posting - Comment Period, Initial Ballot, and Non-binding Poll

Proposed Reliability Standards PRC-024-4 and PRC-029-1, the associated Implementation Plan and other associated documents were posted for a 20-day formal comment period from June 18, 2024 through July 8, 2024, with a parallel additional ballot and non-binding poll held during

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12 *Id.* at items 34, 38.
13 *Id.* at items 39, 42.
14 *Id.* at items 40, 43.
15 *Id.* at item 41.
16 *Id.* at item 36.

the last 10 days of the comment period from June 28, 2024 through July 8, 2024.[17] The additional ballot and non-binding poll results for the proposed Reliability Standards are as follows:

- Proposed Reliability Standard PRC-024-4 received 82.7 percent approval, reaching quorum at 85.98 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 76.51 percent supportive opinions, reaching quorum at 83.07 percent of the ballot pool.[18]
- Proposed Reliability Standard PRC-029-1 received 35.45 percent approval, reaching quorum at 85.39 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 29.03 percent supportive opinions, reaching quorum at 82.47 percent of the ballot pool.[19]
- The Implementation Plan received 48.59 percent approval, reaching quorum at 85.98 percent of the ballot pool.[20]

There were 63 sets of responses, including comments from approximately 138 different individuals and approximately 91 companies, representing 7 industry segments.[21]

K. Third Posting - Comment Period, Initial Ballot, and Non-binding Poll

Proposed Reliability Standard PRC-029-1, the associated Implementation Plan and other associated documents were posted for a 20-day formal comment period from July 22, 2024 through August 12, 2024, with a parallel additional ballot and non-binding poll held during the last 10 days

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17 *Id.* at items 56, 60.

18 *Id.* at items 61, 64.

19 *Id.* at items 62, 65.

20 *Id.* at item 63.

21 *Id.* at item 58.

of the comment period from August 2, 2024 through August 12, 2024.[22] The additional ballot and non-binding poll results for the proposed Reliability Standards are as follows:

- Proposed Reliability Standard PRC-029-1 received 52.89 percent approval, reaching quorum at 89.51 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 42.58 percent supportive opinions, reaching quorum at 88.05 percent of the ballot pool.[23]
- The Implementation Plan received 60.04 percent approval, reaching quorum at 89.3 percent of the ballot pool.[24]

There were 70 sets of responses, including comments from approximately 159 different individuals and approximately 112 companies representing all 10 industry segments.[25]

L. Proceedings under Section 321 of NERC Rules of Procedure

Following the failure of the third ballot for proposed Reliability Standard PRC-029-1, the NERC Board of Trustees took action at its August 15, 2024 meeting to invoke its special authority under Section 321 of the NERC Rules of Procedure.[26] Finding that the ballot body for draft Reliability Standard PRC-024-1 has not approved a proposed Reliability Standard that contains provisions to adequately address specific matters identified in directives issued by the Commission in Order No. 901, the Board directed the Standards Committee to work with NERC Staff to carry out the following instructions, in accordance with NERC Rules of Procedure Section 321.2:

- Convene a public technical conference to discuss the issues surrounding the FERC directives, including whether or not the proposed Reliability Standard PRC-029-1 (and, to the extent necessary, any conforming changes in proposed Reliability

22 *Id*. at items 76, 80.

23 *Id.* at items 81, 83.

24 *Id.* at item 82.

25 *Id.* at item 78.

26 NERC, *Board of Trustees Meeting Minutes* (Aug. 15, 2024), https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Minutes%20-%20BOT%20Open%20-August%2015%202024.pdf.

Standard PRC-024-4) being developed through Project 2020-02 Modifications to PRC-024 (Generator Ride-through) is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified;

- Prepare a memorandum discussing the issues, an analysis of the alternatives considered, and other appropriate matters;
- Use the input from the technical conference to revise the proposed Reliability Standard(s), as appropriate; and
- Re-ballot the proposed Reliability Standard(s) one additional time, with such adjustments are necessary to meet the 45-day deadline provided in NERC Rules of Procedure Rule 321.2.1.

The Standards Committee, working with NERC Staff, convened a technical conference which took place from September 4-5, 2024. This technical conference focused on unresolved issues raised by stakeholders during the comment periods for earlier drafts of proposed Reliability Standard PRC-029-1.[27] Following the technical conference, representatives from the Standards Committee worked with NERC Staff to revise proposed Reliability Standard PRC-029-1 using input from the technical conference and prepare a memorandum discussing the issues, an analysis of the alternatives considered, and other appropriate matters.

M. Fourth Posting - Comment Period, Initial Ballot, and Non-binding Poll for PRC-029-1

Proposed Reliability Standard PRC-029-1, the associated Implementation Plan and other associated documents were posted for a 13-day formal comment period originally scheduled to run from September 13, 2024 through September 30, 2024, with a parallel additional ballot and non-binding poll to be held from September 24, 2024 through September 30, 2024. To allow stakeholders additional time to review the Standards Committee/NERC Staff memorandum, the

27 *Id.* at items 112, 113, 114.

ballot period was extended through October 4, 2024.[28] The additional ballot and non-binding poll results for the proposed Reliability Standard are as follows:

- Proposed Reliability Standard PRC-029-1 received 77.88 percent approval, reaching quorum at 89.51 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 73.6 percent supportive opinions, reaching quorum at 86.85 percent of the ballot pool.[29]
- The Implementation Plan received 77.89 percent approval, reaching quorum at 88.56 percent of the ballot pool.[30]

N. Final Ballot for PRC-024-4

Proposed Reliability Standard PRC-024-4 was posted for a 5-day final ballot period from September 25, 2024 through September 30, 2024. The final ballot for proposed Reliability Standard PRC-024-4 reached quorum at 90.77 percent of the ballot pool, receiving support from 86.41 percent of the voters. The ballot for the Implementation Plan, conducted during the fourth posting for PRC-029-1, reached quorum at 88.56 percent of the ballot pool, receiving support from 77.89 percent of the voters.[31]

O. Board of Trustees Adoption

The NERC Board of Trustees adopted proposed Reliability Standards PRC-024-4 and PRC-029-1 on October 8, 2024.[32]

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28 *Id.* at item 97.

29 Exhibit G, Complete Record of Development at items 98, 100.

30 *Id.* at item 99.

31 *Id.* at item 107.

32 NERC, *Board of Trustees Agenda Package Feb., 2024*, Agenda Item 2b. (Project 2020-2 Modifications to PRC-24 (Generator Ride-through)), https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board%20of%20Trustees%20Open%20Meeting%20Agenda%20Package%20October%208%202024%20Attendees.pdf. In approving proposed Reliability Standard PRC-029-1, the NERC Board of Trustees determined that good cause existed to extend the ballot period past the 45 days prescribed in Section 321.2.1, from September 30, 2024 to October 4, 2024.

P. October 16, 2024 Errata

On October 16, 2024, the Standards Committee approved correcting three errata in proposed Reliability Standard PRC-029-1: one non-substantive error in PRC-029-1 and two non-substantive errors in the implementation plan.[33]

[33] NERC, *Standards Committee Agenda Package Oct. 16,* Agenda Item 3, https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC_Meeting_Agenda_Package-October_16_2024_lp.pdf.

Complete Record of Development

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

Related Files

Status

The final ballot for **PRC-024-4 - Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and Type 2 Wind Resources, and Synchronous Condensers,** concluded at **8 p.m. Eastern, Monday, September 30, 2024.**

The re-ballot ballot for **PRC-029-1-4 - Frequency and Voltage Ride-through Requirements for Inverter-Based Resources,** concluded at **8 p.m. Eastern, Friday, October 4, 2024. Per Rule 321 of the Rules of Procedure, there will be no final ballot.**

Background

The Standards Committee accepted the revised SAR and authorized drafting revisions to the Reliability Standards identified in the SAR on April 19, 2023. The objective of the SAR is to modify PRC-024-3 or replace the standard with a performance-based ride-through standard that ensures generators remain connected to the BPS during system disturbances. Specifically, the SAR focuses on using disturbance monitoring data to substantiate IBR ride-through performance during grid disturbances. The SAR also ensures associated generators that fail to ride-through system events are addressed with a corrective action plan (if possible).

FERC Order 901 requires that IBR-related performance requirements for ride-through are completed and filed with FERC by November 4, 2024. This drafting team will address the IBR-related PRC-029 first and modify PRC-024 to only apply towards synchronous machines. Following the approval of PRC-029, the drafting team will consider additional modifications to PRC-024 to assure performance-based requirements for synchronous machines are adequately addressed per the SAR.

Standard(s) Affected – PRC-024

Purpose/Industry Need

From a risk-based perspective, the goal of the standard is to mitigate the ongoing and systemic performance issues identified across multiple Interconnections and across many disturbances analyzed by NERC and the Regions. Ongoing NERC reports and findings from NERC alerts have continued to substantiate that IBR are failing to ride-through in accordance with expectations and multiple NERC guidelines. These issues have been identified in IBRs as well as synchronous generators, with many causes of tripping entirely unrelated to voltage and frequency protection settings as dictated by the currently effective version of PRC-024.

Subscribe to this project's observer mailing list

Select "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2020-02 Modifications to PRC-024 (Generator Ride-through) Observer List" in the Description Box.

Draft	Actions	Dates	Results	Consideration of Comments
Errata for Draft 4 **PRC-029-1** **(108)** Clean | **(109)** Redline **Implementation Plan** **(110)** Clean | **(111)** Redline	The Standards Committee approved on October 16, 2024			
Final Draft **PRC-024-4** **(101)** Clean **(102)** Redline to Last Posted | **(103)** Redline to Last Approved **Supporting Materials** **Technical Rationale** **(104)** PRC-024-4 **VRF/VSL Justifications** **(105)** PRC-024-4	**Final Ballot** **(106)** Info Vote	09/25/24 - 09/30/24	Ballot Results **(107)** PRC-024-4	
Draft 4 **PRC-029-1** **(84)** Clean | **(85)** Redline to Last Posted **(86)** Implementation Plan **Supporting Materials** **(87)** NERC and Standards Committee Memo - Summary of Issues and Alternatives Considered *NEW ***See Addendum items 112 - 114 for Materials from the September 2024 Technical Conference Convened Under Section 321 of the NERC Rules of Procedure*** **(88)** Unofficial Comment Form (Word) **PRC-029-1 Technical Rationale** **(89)** Clean | **(90)** Redline to Last Posted **PRC-029-1 VRF/VSL Justifications** **(91)** Clean | **(92)** Redline to Last Posted **(93)** Consideration of Directives from FERC Order 901	Additional Ballots and Non-binding Poll **(96)** Ballot Reminder **(97)** Info Vote	09/24/24 - 10/04/24 (extended to allow for review of NERC/ Standards Committee Memo)	Ballot Results **(98)** PRC-029-1 **(99)** Implementation Plan **(100)** Non-binding Poll	
	Comment Period **(94)** Info Submit Comments	09/17/24 - 09/30/24	**(95)** Comments Received	
Draft 3 PRC-029-1 **(66)** Clean | **(67)** Redline to Last Posted Implementation Plan **(68)** Clean | **(69)** Redline to Last Posted **Supporting Materials** **(70)** Unofficial Comment Form (Word) PRC-029-1 Technical Rationale **(71)** Clean | **(72)** Redline to Last Posted PRC-029-1 VRF/VSL Justifications **(73)** Clean | **(74)** Redline to Last Posted **(75)** Consideration of Directives from FERC Order 901	Additional Ballots and Non-binding Poll **(79)** Ballot Open Reminder **(80)** Info Vote	08/02/24 - 08/12/24	Ballot Results **(81)** PRC-029-1 **(82)** Implementation Plan **(83)** Non-binding Poll	
	Comment Period **(76)** Info Submit Comments	07/22/24 - 08/12/24	**(77)** Comments Received	**(78)** Consideration of Comments
Draft 2 PRC-024-4 **(44)** Clean | **(45)** Redline PRC-029-1 **(46)** Clean | **(47)** Redline **(48)** Implementation Plan **Supporting Materials** **(49)** Unofficial Comment Form (Word)	Additional Ballots and Non-binding Polls **(59)** Ballot Open Reminder **(60)** Info Vote	06/28/24 - 07/08/24	Ballot Results **(61)** PRC-024-4 **(62)** PRC-029-1 **(63)** Implementation Plan Non-binding Poll Results	

Technical Rationales **(50)** PRC-024-4 PRC-029-1 **(51)** Clean | **(52)** Redline VRF/VSL Justifications **(53)** PRC-024-4 PRC-029-1 **(54)** Clean | **(55)** Redline			**(64)** PRC-024-4 **(65)** PRC-029-1	
	Comment Period **(56)** Info Submit Comments	06/18/24 - 07/08/24	**(57)** Comments Received	**(58)**Consideration of Comments
Draft 1 PRC-024-4 **(25)** Clean | **(26)** Redline **(27)** PRC-029-1 **(28)** Implementation Plan **Supporting Materials** **(29)** Unofficial Comment Form (Word) Technical Rationales **(30)** PRC-024-4 **(31)** PRC-029-1 VRF/VSL Justifications **(32)** PRC-024-4 **(33)** PRC-029-1	Initial Ballots and Non-binding Polls **(37)** Ballot Open Reminder **(38)** Info Vote	04/12/24 - 04/22/24	Ballot Results **(39)** PRC-024-4 **(40)** PRC-029-1 **(41)** Implementation Plan Non-binding Poll Results **(42)** PRC-024-4 **(43)** PRC-029-1	
	Join Ballot Pools	03/27/24 - 04/05/24		
	Comment Period **(34)** Info Submit Comments	03/27/24 - 04/22/24	**(35)** Comments Received	**(36)** Consideration of Comments
(24) Waiver	The Standards Committee approved the waiver on December 13, 2023			
PRC-024 Standard Authorization Request **(22)** Clean | **(23)** Redline	The Standards Committee accepted the SAR on April 19, 2023			
(17) PRC-024 Standard Authorization Request **Supporting Materials** **(18)** Unofficial Comment Form (Word)	Comment Period **(19)** Info Submit Comments	05/31/22 - 07/14/22	**(20)** Comments Received	**(21)** Consideration of Comments
Drafting Team Nominations **(15)** Unofficial Nomination Form (Word)	Nomination Period **(16)** Info Submit Nominations	05/31/22 - 07/14/22		
Standard Authorization Request **(13)** Clean | **(14)** Redline	The Standards Committee accepted the SAR on April 20, 2022			
Supplemental Drafting Team Nominations **Supporting Materials** **(11)** Unofficial Nomination Form (Word)	Nomination Period **(12)** Info Submit Nominations	11/19/21 - 12/20/21		
Supplemental Drafting Team Nominations **Supporting Materials** **(9)** Unofficial Nomination Form (Word)	Nomination Period **(10)** Info Submit Nominations	04/28/21 - 05/17/21		
(3) Standard Authorization Request **Supporting Materials** **(4)** Unofficial Comment Form (Word) **(5)** Transmission-connected Dynamic Reactive Resources White Paper	Comment Period **(6)** Info (Updated) Submit Comments	03/30/20 - 05/13/20(Extended)	**(7)** Comments Received	**(8)**Consideration of Comments
Drafting Team Nominations **Supporting Materials** **(1)** Unofficial Nomination Form (Word)	Nomination Period **(2)** Info (Updated) Submit Nominations	03/30/20 - 05/13/20(Extended)		

Additional Materials from the September 2024 Technical Conference Convened under Section 321 of the NERC Rules of Procedure

Standards Committee & NERC Generator Ride-through (PRC-029-1) Technical Conference

(112) Agenda, Panelist Bios, Presentations

Day 1 Recording | **(113)** Transcript

Day 2 Recording | **(114)** Transcript

Unofficial Nomination Form

Project 2020-02 Transmission-connected Resources Standard Authorization Request Drafting Team

Do not use this form for submitting nominations. Use the electronic form to submit nominations for **Project 2020-02 Transmission-connected Resources** Standard Authorization Request (SAR) drafting team members by **8 p.m. Eastern, Wednesday, May 13, 2020.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Chris Larson (via email), or at 404-446-9708.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Background

The problem of increasing amounts of reactive power being supplied by nonsynchronous sources was identified in NERC's 2017 Long-term Reliability Assessment. In response to the concern, the Planning Committee (PC) assigned the System Analysis and Modeling Subcommittee (SAMS) to study the issue. The SAMS developed the *Applicability of Transmission-Connected Reactive Devices* white paper, which was approved by the PC at its December 10-11, 2019 meeting. The PC Executive Committee reviewed the draft SAR from SAMS at its January meeting and subsequently approved the SAR by email vote ending on February 11, 2020. The SAR concerning Transmission-Connected Resources (TCR) aims to modify NERC Reliability Standards MOD-025, MOD-026, MOD-027, PRC-019 and PRC-024 to comprehensively include all types of dynamic reactive resources (including static var systems and FACTS) and DC transmission systems used to provide Essential Reliability Services (ERS) in the Bulk Electric System (BES).

Dynamic reactive resources used to provide ERS in the BES include generation resources (rotating machine and inverter-based) as well as transmission connected dynamic reactive resources (power-electronics based). Existing Reliability Standards for verifying the capability, modeling and performance of dynamic reactive resources are only applicable to Facilities comprising generation resources. Augmenting the applicability of these standards to include (nongeneration) transmission-connected reactive resources, both rotating machine (i.e. synchronous condenser) and power-electronics based, will enhance the BES reliability by ensuring that the capability, models and performance are verified and validated for all varieties of dynamic reactive resources utilized in providing ERS in the BES.

Standard(s) affected: MOD-025, MOD-026, MOD-027, PRC-019 and PRC-024
Drafting Team activities include participation in technical conferences, stakeholder communications and outreach events, periodic drafting team meetings and conference calls. Approximately one face-to-face meeting per quarter can be expected (on average three full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the drafting team sets forth. NERC is seeking individuals who possess experience in the following areas:

- Developing and verifying dynamic models used in long-term planning assessments, specifically for transmission-connected reactive resources*
- Modeling and studying transmission-connected reactive devices during interconnection studies or long-term planning assessments
- Performing equipment capability testing for transmission-connected reactive devices and rotating machines
- Understanding the large disturbance behavior of transmission-connected reactive devices, particularly the power electronic controls that govern the performance of these devices during abnormal grid conditions

* Transmission-connected reactive resources generally refers to FACTS (Flexible AC Transmission System) devices such as Static Var Compensators (SVCs) and Static Synchronous Compensator (STATCOMs) as well as other power-electronic devices that fall in this category such as HVDC circuits and synchronous condensers.

Name:	
Organization:	
Address:	
Telephone:	
Email:	
Please briefly describe your experience and qualifications to serve on the requested SAR Drafting Team (Bio):	
If you are currently a member of any NERC drafting team, please list each team here: ☐ Not currently on any active SAR or standard drafting team. ☐ Currently a member of the following SAR or standard drafting team(s):	

If you previously worked on any NERC drafting team please identify the team(s): ☐ No prior NERC SAR or standard drafting team. ☐ Prior experience on the following team(s):
Acknowledgement that the nominee has read and understands both the *NERC Participant Conduct Policy* and the *Standard Drafting Team Scope* documents, available on NERC Standards Resources. ☐ Yes, the nominee has read and understands these documents.

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:		
☐ MRO ☐ NPCC ☐ RF	☐ SERC ☐ Texas RE ☐ WECC	☐ NA – Not Applicable

Select each Industry Segment that you represent:	
☐	1 — Transmission Owners
☐	2 — RTOs, ISOs
☐	3 — Load-serving Entities
☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	6 — Electricity Brokers, Aggregators, and Marketers
☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users
☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:	
☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		Email:	
Name:		Telephone:	
Organization:		Email:	

Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

UPDATED
Standards Announcement

Project 2020-02 Transmission-connected Dynamic Reactive Resources

Nomination Period Now Open through May 13, 2020

Now Available

Nominations are being sought for **Project 2020-02 Transmission-connected Dynamic Reactive Resources** drafting team members. The due date has been extended, and is now open through **8 p.m. Eastern, Wednesday, May 13, 2020**.

Use the electronic form to submit a nomination. Contact Wendy Muller regarding issues using the electronic form. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls. Previous drafting team experience is beneficial but not required.

See the project page (linked above) and nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the drafting team in May 2020. Nominees will be notified shortly after they have been appointed.

For information on the Standards Development Process, refer to the Standard Processes Manual.

Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2020-02 Transmission-connected Resources observer list” in the Description Box. For more information or assistance, contact Senior Standards Developer, Chris Larson (via email) or at 404-446-9708.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Revise the Applicable Facilities of MOD-025, MOD-026, MOD-027, PRC-019 and PRC-024 Standards to comprehensively include all types of dynamic reactive resources (including static var systems and FACTS) and DC transmission systems used to provide Essential Reliability Services in the Bulk Electric System.		
Date Submitted:	February 24, 2020		
SAR Requester			
Name:	Hari Singh – Chair, System Analysis & Modeling Subcommittee (SAMS)		
Organization:	Xcel Energy		
Telephone:	303-571-7095	Email:	hari.singh@xcelenergy.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
Dynamic reactive resources used to provide Essential Reliability Services (ERS) in the BES include generation resources (rotating machine and inverter-based) as well as transmission connected dynamic reactive resources (power-electronics based). Existing reliability standards for verifying the capability, modeling and performance of dynamic reactive resources are only applicable to Facilities comprising generation resources. Augmenting the applicability of these standards to include (non-generation) transmission-connected reactive resources – both rotating machine (i.e. synchronous condenser) and power-electronics based – will enhance the BES reliability by ensuring that the capability, models and performance is verified and validated for all varieties of dynamic reactive resources utilized in providing ERS in the BES.			

Requested information
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
Augment the "Applicability – Facilities" and "Applicability-Functional Entities" sections in MOD-025, MOD-026, MOD-027, PRC-019 and PRC-024 reliability standards to address (non-generation) transmission-connected dynamic reactive resources – both rotating machine (i.e. synchronous condenser) and power-electronics based. Also modify Requirements (including applicable attachments) as needed to ensure they continue to address the additional Facilities. As needed, also define new Glossary Terms for all or some of the transmission-connected dynamic reactive devices noted in the SAMS white-paper "*Transmission Connected Dynamic Reactive Resources – Assessment of Applicability in Reliability Standards*".
Project Scope (Define the parameters of the proposed project):
Revise the "Applicability – Facilities" section, "Applicability – Functional Entities" section, and Requirements (including applicable attachments) as needed in MOD-025, MOD-026, MOD-027, PRC-019 and PRC-024 reliability standards to comprehensively address all varieties of transmission-connected dynamic reactive resources that are utilized in providing ERS in the BES.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1]which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):
The "Applicability – Facilities" and "Applicability-Functional Entities" sections in MOD-025, MOD-026, MOD-027, PRC-019 and PRC-024 reliability standards will be revised to address (non-generation) transmission-connected dynamic reactive resources based on the recommendations summarized in Table 1 of the SAMS white-paper "*Transmission Connected Dynamic Reactive Resources – Assessment of Applicability in Reliability Standards*". The white-paper also provides the technical justifications for the recommended revisions and the associated reliability benefits. Also modify Requirements (including applicable attachments) as needed to ensure they continue to address the additional Facilities. As needed, also define new Glossary Terms for all or some of the transmission-connected dynamic reactive devices noted as items 1.a – 1.j in the Additional Considerations section of the SAMS white-paper.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Unknown
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
Power-electronics based transmission-connected reactive resources – also known as FACTS (Flexible AC Transmission System) devices – such as: Static Var Compensator (SVC), Static Synchronous Compensator (STATCOM), HVDC Links (LCC or VSC).
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*. Transmission

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Transmission Owners in addition to the existing Functional Entities
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
"*Transmission Connected Dynamic Reactive Resources – Assessment of Applicability in Reliability Standards*" white-paper approved by SAMS members.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
PRC-019 SAR requested by SPCS and PRC-024 SAR requested by IRPTF
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
No viable alternatives were found by SAMS.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g. NPCC	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
☒ Draft SAR reviewed by NERC Staff ☒ Draft SAR presented to SC for acceptance ☒ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

Unofficial Comment Form

Project 2020-02 Transmission-connected Resources Standard Authorization Request

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System to submit comments on the **Project 2020-02 Transmission-connected Resources Standard Authorization Request** by **8 p.m. Eastern, Wednesday, May 13, 2020.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Chris Larson (via email), or at 404-446-9708.

Background

The potential risk of increasing amounts of reactive power being supplied by nonsynchronous sources was identified in NERC's 2017 Long-term Reliability Assessment. In response to the concern, the Planning Committee (PC) assigned the System Analysis and Modeling Subcommittee (SAMS) to study the issue. The SAMS developed the *Applicability of Transmission-Connected Reactive Devices* white paper, which was approved by the PC at its December 10-11, 2019 meeting. The PC Executive Committee reviewed the draft SAR from SAMS at its January meeting and subsequently approved the SAR by email vote ending on February 11, 2020. The SAR concerning Transmission-Connected Resources (TCR) aims to modify NERC Reliability Standards MOD-025, MOD-026, MOD-027, PRC-019 and PRC-024 to comprehensively include all types of dynamic reactive resources (including static var systems and FACTS) and DC transmission systems used to provide Essential Reliability Services (ERS) in the Bulk Electric System (BES).

Dynamic reactive resources used to provide ERS in the BES include generation resources (rotating machine and inverter-based) as well as transmission connected dynamic reactive resources (power-electronics based). Existing Reliability Standards for verifying the capability, modeling and performance of dynamic reactive resources are only applicable to Facilities comprising generation resources. Augmenting the applicability of these standards to include (nongeneration) transmission-connected reactive resources, both rotating machine (i.e. synchronous condenser) and power-electronics based, will enhance the BES reliability by ensuring that the capability, models and performance are verified and validated for all varieties of dynamic reactive resources utilized in providing ERS in the BES.

Questions

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

   ☐ Yes
   ☐ No

   Comments:

2. Provide any additional comments for the SAR drafting team to consider, if desired.

   Comments:

Transmission Connected Dynamic Reactive Resources and HVDC Equipment – Assessment of Applicability in Reliability Standards

NERC SAMS White Paper
February 2019

Background

The bulk power system (BPS) in North America continues to experience a change in generating resources, technologies, and transmission system devices used to provide essential reliability services (ERS) such as voltage control, frequency control, and ramping/balancing capability. In particular, the BPS is experiencing a rapid change in generation resource mix, with an increasing installation base of inverter-based generation resources and accompanying retirements of synchronous generation resources. Additionally, generation is increasingly being located farther from load centers than it was in the past. These factors are contributing to an increased reliance on non-generation transmission-connected dynamic reactive resources – both rotating machine (i.e. synchronous condenser) and power-electronics based – to provide ERS in the BPS. Synchronous condensers are being used to provide dynamic reactive power and transient voltage support, as well as synchronous inertia and fault current contribution in weak grid conditions. Static var compensators (SVCs) and static compensators (STATCOMs) are increasingly being used to provide dynamic reactive power and transient voltage support.

Many relevant NERC Reliability Standards are not applicable to these types of transmission-connected dynamic reactive resources. It is now clear that an increasing number of these reactive resources are being used to provide the same ERS as generation resources to ensure reliability of the BPS. In many cases, these types of dynamic reactive resources are critical to BPS reliability because they are used to increase power transfer capability, mitigate system instability, provide grid resilience for physical and cyber attacks, and provide safety nets for severe contingencies. In this respect, ensuring their electrical capability, verification of performance, and ability to ride through grid events is no less important than for traditional generators.

The NERC Planning Committee and the NERC System Analysis and Modeling Subcommittee (SAMS) expressed concerns that the existing NERC Reliability Standards may not clearly address non-generation transmission-connected dynamic reactive resources. In response to these concerns, SAMS has developed this white paper that comprises an assessment of the applicability of relevant NERC Reliability Standards to such dynamic reactive resources and provides recommendations to address any identified reliability gap. In particular, SAMS focused on the following NERC Reliability Standards:

- **MOD-025-2:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability
- **MOD-026-1:** Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

- **MOD-027-1:** Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions
- **MOD-032-1:** Data for Power System Modeling and Analysis
- **PRC-019-2:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection
- **PRC-024-2:** Generator Frequency and Voltage Protective Relay Settings

Results from this assessment and recommendations for moving forward are provided in this white paper.

Applicability Assessment

SAMS reviewed relevant NERC Reliability Standards related to the model verification, capability testing, disturbance ride through, and protection coordination aspects of generation resources to evaluate if the transmission-connected dynamic reactive resources are included within the applicability sections of these standards. The goal was to determine the reliability need/justification for including transmission-connected dynamic reactive resources as applicable Facilities within the Applicability section of these standards.

Recommended Applicability

Table 1 shows the applicability of relevant NERC Reliability Standards to dynamic reactive resources – including both generation resources and non-generation transmission connected reactive resources. The cells with green bold font show the existing applicability and the cells with red bold italicized font show the recommended applicability based on this SAMS assessment .

For the assessed non-generation reactive resources (refer to Appendix A for their descriptions), each cell includes either a Yes or N/A as the recommendation for its inclusion as Facilities in the Applicability section of the relevant Reliability Standard. The technical basis and justification for the recommended applicability is provided in the following sub-sections.

Table 1: Applicability of Relevant NERC Reliability Standards to Dynamic Reactive Resources

	MOD-025	MOD-026	MOD-027	MOD-032	PRC-019	PRC-024
Synchronous Generator	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Inverter-Based[1] Generator	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Synchronous Condenser	**Yes**	***Yes***	***N/A***	**Yes**	**Yes**	***Yes***
SVC	***Yes***	***Yes***	***N/A***	**Yes**	***Yes***	***Yes***
STATCOM	***Yes***	***Yes***	***N/A***	**Yes**	***Yes***	***Yes***
LCC HVDC	***N/A***	***N/A***	***Yes***	**Yes**	***Yes***	***Yes***
VSC HVDC	***Yes***	***Yes***	***Yes***	**Yes**	***Yes***	***Yes***

Existing applicability
SAMS recommendation

[1] Nonsynchronous generating resource

Technical Basis for Applicability

The sub-sections below describe the technical basis and justification for applicability of the relevant NERC Reliability Standard to each type of transmission-connected dynamic reactive resource listed in Table 1.

MOD-025

The purpose of MOD-025 is to ensure that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability. The technical justification for applicability of MOD-025 recommended in Table 1 is described below:

- **SVC:** A SVC serves many of the same purposes as a synchronous condenser, particularly the injection or absorption of dynamic reactive power to support steady-state and transient voltage conditions. Similar to a synchronous condenser, an SVC has a current injection capability that translates to a reactive power capability based on terminal voltage. For this reason, a power electronics resource like a SVC connected to the BPS should be a Facility to which MOD-025 is applicable for reactive power capability verification.
- **STATCOM:** A SVC and STATCOM are very similar in terms of being power electronic resources connected to the BPS that provide steady-state and dynamic voltage support. The STATCOM and SVC differ in their reactive capability, particularly under off-nominal voltage conditions. Their controls are also different based on the types of equipment technologies used in the different devices. Again, the power electronics have a current injection capability that translates to reactive power capability based on voltage. For this reason, STATCOM should be a Facility to which MOD-025 is applicable for reactive power capability verification.
- **LCC HVDC:** A LCC HVDC circuit is predominantly used to transfer large amounts of active power across long distances (as well as other applications such as underground cables, etc.). LCC HVDC technology inherently consumes very large quantities of reactive power at the converters. AC filters located at the converter terminals to mitigate harmonics also provide reactive power and offset its consumption from the grid. However, ac filters are comprised of static shunt reactive devices with known reactive capability ratings that do not need verification. LCC HVDC does not have independent control of active and reactive power because there is no voltage source within the converters. For these reasons, LCC HVDC should ***not*** be a Facility to which MOD-025 is applicable for reactive power capability verification.
- **VSC HVDC:** VSC HVDC is different than LCC HVDC in that it has independent control of active and reactive power because of the independent voltage source within the converters. Therefore, these elements are able to operate in automatic voltage control, controlling their terminal voltage (or some other compensated voltage) to support scheduled voltages on the BPS. Therefore, VSC HVDC should be a Facility to which MOD-025 is applicable for reactive power capability verification.

MOD-026

The purpose of MOD-026 is to verify that the generator excitation control system or plant volt/var control function model (including the power system stabilizer model and the impedance compensator model) and the model parameters used in dynamic simulations accurately represent the generator excitation control system or plant volt/var control function behavior when assessing Bulk Electric System

(BES) reliability. The technical justification for applicability of MOD-026 recommended in Table 1 is described below:

- **Synchronous Condenser:** A synchronous condenser is a synchronous machine without a prime mover (freely rotating shaft) and therefore delivers/absorbs reactive power to the BPS based on its excitation. In essence, a synchronous condenser exhibits the same dynamic behavior as a synchronous generator from the perspectives of MOD-026. A synchronous condenser should be required to provide verified dynamic models as described in MOD-026.
- **SVC:** SVCs provide dynamic reactive power to the BPS to support grid voltage, voltage stability, and power transfers. These devices include elements and controls that can respond very quickly to grid conditions (during and after faults, for example). There are no (or minimal) moving parts in these devices, and the majority of the response is determined based on the settings programmed into the controls. It is important that these control settings are verified, and the dynamic response of the model matches reality. For these reasons, SVCs should be required to provide verified dynamic models as per the intent of MOD-026.
- **STATCOM:** STATCOMs use different technology than SVCs, but they also provide dynamic reactive power to the BPS and their response is determined based on the settings programmed into the controls. Therefore, similar to SVCs, STATCOMs should be required to provide verified dynamic models as per the intent of MOD-026.
- **LCC HVDC:** For the same reasons listed in MOD-025, LCC HVDC should ***not*** be a Facility to which MOD-026 is applicable.
- **VSC HVDC:** Similar to SVCs and STATCOMs, VSC HVDC Facilities also provide dynamic reactive power to the BPS and their response is determined based on the settings programmed into the controls. Therefore, VSC HVDC should be required to provide verified dynamic models as per the intent of MOD-026.

MOD-027

The purpose of MOD-027 is to verify that the turbine/governor and load control or active power/frequency control model and the model parameters, used in dynamic simulations that assess Bulk Electric System (BES) reliability, accurately represent generator unit real power response to system frequency variations. The technical justification for applicability of MOD-027 recommended in Table 1 is described below:

- **Synchronous Condenser:** A synchronous conderser is a dynamic reactive power resource and does not have the capability to provide active power to the BPS. It does not include a turbine-governor or active power-frequency control system. Therefore, MOD-027 is not applicable..
- **SVC:** It does not include a turbine-governor or active power-frequency control system. Therefore, SVC should ***not*** be a Facility to which MOD-027 is applicable.
- **STATCOM:** A STATCOM is a dynamic reactive power resource and does not have the capability to provide active power to the BPS. It does not include a turbine-governor or active power-frequency control system. Therefore, STATCOM should ***not*** be a Facility to which MOD-027 is applicable.
- **LCC HVDC:** Although LCC HVDC is *not* a dynamic reactive power resource, it has the capability to provide active power/frequency control to the BPS. Since its active power/frequency control system

response is determined based on the settings programmed into the controls, it should be required to provide verified dynamic models as per the intent of MOD-027.

- **VSC HVDC:** A VSC HVDC is a dynamic reactive power resource and also has the capability to provide active power/frequency control to the BPS. Since its active power/frequency control system response is determined based on the settings programmed into the controls, it should be required to provide verified dynamic models as per the intent of MOD-027.

MOD-032

MOD-032 has sufficiently comprehensive applicability to include transmission-connected dynamic reactive resources for the purposes of obtaining their modeling data. Therefore, SAMS does not recommend any changes to the applicability of MOD-032.

PRC-019

The purpose of PRC-019 is to verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings. The technical justification for applicability of PRC-019 recommended in Table 1 is described below:

- **Synchronous Condenser:** A synchronous condenser is protected with a number of protective functions and limiters, similar to a synchronous generator. If not properly coordinated, the limiters and protection elements could potentially limit the output or trip the machine below its rated capability. Therefore, PRC-019 should be applicable to synchronous condensers.
- **SVC:** Analogous to the synchronous machines, SVCs have voltage regulating controls, limiters, and protection functions. If not properly coordinated, the limiters and protection elements could potentially limit the output or trip the SVC below its rated capability. Therefore, PRC-019 should be applicable to SVCs.
- **STATCOM:** Analogous to the SVCs, STATCOMs have active and reactive voltage regulating controls, limiters, and protection functions. If not properly coordinated, the limiters and protection elements could potentially limit the output or trip the STATCOM below its rated capability. Therefore, PRC-019 should be applicable to STATCOMs.
- **LCC HVDC:** LCC HVDC does not have independent control of active and reactive power because there is no voltage source within the converters. To the extent that LCC HVDC has voltage regulating controls, limiters, and protection functions, they, they could potentially limit the LCC HVDC output below its rated capability if not properly coordinated. PRC-019 should be applicable to LCC HVDC due to its control and protection equipment abilities.
- **VSC HVDC:** VSC HVDC does have independent control of active and reactive power because they use voltage source converters. Analogous to the SVCs and STATCOMs, the VSC HVDC has voltage regulating controls, limiters, and protection functions. If not properly coordinated, the limiters and protection elements could potentially limit the VSC HVDC output below its rated capability. PRC-019 should be applicable to VSC HVDC due to its control and protection equipment abilities.

PRC-024

In the “Evaluating Protective Relay Settings” section of PRC-024 --Attachement 2 Item #2 states that the GO must “Evaluate voltage protective relay settings assuming that additional installed generating plant reactive support equipment (such as static VAR compensators, synchronous condensers, or capacitors) is available and operating normally.” However,this evaluation focuses on reactive power devices within the generating plant and does not include similar reactive power devices that are transmission connected.

The purpose of PRC-024 is to ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions. The technical justification for applicability of PRC-024 recommended in Table 1 is described below:

- **Synchronous Condenser:** Synchronous condensers, like synchronous generators, have frequency and voltage protective relays whose settings should not be within the ride through characteristics of PRC-024. Undervoltage and overvoltage protection, overspeed protection, etc., are all applied to a synchronous condenser since it is inherently a rotating electric machine without a prime mover. The synchronous condenser is expected to ride through grid voltage and frequency excursion events to provide dynamic voltage support and provide system inertia for stabilizing wide-area system frequency. Therefore, PRC-024 should be applicable to synchronous condensers.
- **SVC:** SVCs provide dynamic reactive power support during and immediately after a grid disturbance during the transient timeframes. In this respect, its purpose and functionalty is very similar to that of synchronous condensers (and synchronous generators). The SVC would be expected to ride through grid voltage and frequency excursion events to provide dynamic voltage supportsupport herefore, PRC-024 should be applicable to SVCs.
- **STATCOM:** STATCOMs provide dynamic reactive power support during and immediately after a grid disturbance during the transient timeframes. In this respect, its purpose and functionalty is very similar to that of synchronous condensers and SVCs. The STATCOM would be expected to ride through grid voltage and frequency excursion events to provide dynamic voltage support. PRC-024 should be applicable to STATCOM.
- **LCC HVDC:** The LCC HVDC would be expected to ride through grid voltage and frequency excursion events to provide continuity of service (i.e. maintaining MW output). Therefore, PRC-024 should not be applicable to LCC HVDC.
- **VSC HVDC:** VSC HVDC provide dynamic reactive power support during and immediately after a grid disturbance during the transient timeframes. In this respect, its purpose and functionalty is very similar to that of SVCs and STATCOMs. The VSC HVDC would be expected to ride through grid voltage and frequency excursion events to provide dynamic voltage support. Therefore, PRC-024 should be applicable to VSC HVDC.

Other Considerations

The following additional considerations were noted during the assessment. While not necessarily directly related to the assessment of applicability of elements to relevant NERC Standards, SAMS believes these additional topics are important and should be addressed.

1. Definitions for the following terms should be reviewed for potential additions and/or revisions in the NERC Glossary of Terms include, but are not limited to, the following:
    a. Generator (or Generating Facility)
    b. Generating Unit Capability[2]
    c. Dynamic Reactive Power
    d. Synchronous Condenser
    e. Static Var Compensator (SVC)
    f. Static Synchronous Compensator (STATCOM)
    g. High Voltage DC (HVDC)
    h. Line Commutated Converter (LCC) HVDC
    i. Voltage Source Converter (VSC) HVDC
    j. Flexible AC Transmission Systems (FACTS)
2. NERC SAMS and the NERC Power Plant Modeling and Verification Task Force (PPMVTF) have both identified a significant inconsistency between the intent of MOD-025-2 to "ensure that accurate information on generator…capability[3] is available for planning models used to assess Bulk Electric System (BES) reliability" and the actual results obtained during testing. MOD-025-2 does not require the full (maximum achievable) reactive capability of the resource to be reached via test. This is warranted because the testing conditions likely will limit the resource from reaching its full (maximum achievable) reactive capability before other limits are reached such as system voltage, generator terminal voltage, or auxiliary bus voltage limits. While this is reasonable for testing, the standard does not require calculations to be performed to prove that the resource could reach its full (maximum achievable) reactive capability under more favorable operating conditions (i.e. when that full reactive capability is needed for maintaining voltage schedule). Therefore, there is a significant misconception in the industry that the testing results should be used as the same data submitted for MOD-032-1 for capability of the machine. This misconception is likely leading to incorrect data being supplied for the purposes of MOD-032-1 and is driven by the requirements in MOD-025-2.

[2] This is a defined term; however, the definition is not sufficiently reflective of the term.

[3] and synchronous condenser reactive power capability

UPDATED
Standards Announcement

Project 2020-02 Transmission-connected Dynamic Reactive Resources Standard Authorization Request

Informal Comment Period Now Open through May 13, 2020

Now Available

The informal comment period for **Project 2020-02 Transmission-connected Resources Standard Authorization Request** *has been extended and is now open through* ***8 p.m. Eastern, Wednesday, May 13, 2020.***

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. Contact Wendy Muller regarding issues with the SBS. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every* ***6 months*** *and must be reset.*
- *The SBS* ***is not*** *supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to* ***allow at least 48 hours*** *for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts* ***prior to the last day*** *of a comment/ballot period.*

Next Steps

The drafting team will review all responses received during the comment period and determine the next steps of the project**.**

For information on the Standards Development Process, refer to the Standard Processes Manual**.**

Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2020-02 Transmission-connected Resources observer list” in the Description Box. For more information or assistance, contact Senior Standards Developer, Chris Larson (via email) or at 404-446-9708.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2020-02 Transmission-connected Resources | Standard Authorization Request
Comment Period Start Date:	3/30/2020
Comment Period End Date:	5/13/2020
Associated Ballots:	

There were 39 sets of responses, including comments from approximately 118 different people from approximately 100 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

2. Provide any additional comments for the SAR drafting team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
DTE Energy - Detroit Edison Company	Adrian Raducea	3,4,5		DTE Energy - DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Daniel Herring	DTE Energy - Detroit Edison Company	4	RF
					Adrian Raducea	DTE Energy - Detroit Edison	5	RF
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Andy Crooks	SaskPower Corporation	1	MRO
					Bryan Sherrow	Kansas City Board of Public Utilities	1	MRO
					Bobbi Welch	Omaha Public Power District	1,3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Bobbi Welch	Midcontinent ISO	2	MRO
					Douglas Webb	Kansas City Power & Light	1,3,5,6	MRO
					Fred Meyer	Algonquin Power Co.	1	MRO
					John Chang	Manitoba Hydro	1,3,6	MRO
					James Williams	Southwest Power Pool, Inc.	2	MRO
					Jamie Monette	Minnesota Power / ALLETE	1	MRO

					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Sing Tay	Oklahoma Gas & Electric	1,3,5,6	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Troy Brumfield	American Transmission Company	1	MRO
Westar Energy	Douglas Webb	1,3,5,6	MRO,SPP RE	Westar-KCPL	Doug Webb	Westar	1,3,5,6	MRO
					Doug Webb	KCP&L	1,3,5,6	MRO
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Amber Skillern	East Kentucky Power Cooperative	1	SERC
					Ben Engelby	Arizona Electric Power Cooperative, Inc.	1	WECC
					Steven Myers	North Carolina EMC	3,4,5	SERC
					Meredith Dempsey	Brazos Electric Cooperative	1,5	Texas RE
					Ryan Strom	Buckeye Power, Inc.	5	RF
					Calvin Wheatley	Wabash Valley Power Association	1	RF
					Kylee Kropp	Sunflower Electric Power Corporation	1	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC

					Greg Cecil	Duke Energy	6	RF
Northern California Power Agency	Marty Hostler	3,4,5,6		NCPA	Michael Whitney	Northern California Power Agency	3	WECC
					Scott Tomashefsky	Northern California Power Agency	4	WECC
					Dennis Sismaet	Northern California Power Agency	6	WECC
					Marty	Northern California Power Agen	5	WECC
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Eversource Energy	Quintin Lee	1,3		Eversource Group	Sharon Flannery	Eversource Energy	3	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
NPCC	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State	7	NPCC

	Reliability Council		
David Burke	Orange & Rockland Utilities	3	NPCC
Michele Tondalo	UI	1	NPCC
Helen Lainis	IESO	2	NPCC
John Pearson	ISO-NE	2	NPCC
David Kiguel	Independent	7	NPCC
Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
Nick Kowalczyk	Orange and Rockland	1	NPCC
Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Shivaz Chopra	New York Power Authority	5	NPCC
Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC

					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Nurul Abser	NB Power Corporation	1	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC
					Jim Grant	NY-ISO	2	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Silvia Parada Mitchell	NextEra Energy, LLC	4	NPCC
					Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					John Hasting	National Grid USA	1	NPCC
					Michael Jones	National Grid USA	1	NPCC
					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments". The NSRF agrees with the intent of the SAR but please see our main objection in question 2, a definition of Essential Reliable Service is required.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	No
Document Name	
Comment	
To minimize churn among standard versions, Reclamation recommends the SAR drafting team coordinate changes with other existing drafting teams for related standards; specifically, MOD-032, Project 2017-07, and the Standards Efficiency Review Phase 2.	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC generally agrees with the proposed scope and purpose of the SAR. However, the SAR should be modified to more clearly identify the BES nature of the equipment that is in scope and whether it qualifies as "transmission connected." The term "transmission connected" is ambiguous since many regions have different definitions for what is considered transmission. The SAR should be clarified to address this ambiguity.	

Additionally, “transmission connected” does not indicate if the dynamic reactive resource itself must be classified as BES, in accordance with NERC’s definition, to be within the SAR’s scope or if the dynamic reactive resource must simply be connected to an existing BES element to be within the SAR’s scope. ATC believes that non-BES devices should not fall within the scope of the standards affected (MOD-025, MOD-026, MOD-027, PRC-019, and PRC-024) such that a device connected to distribution facilities or other non-BES facilities (e.g. DERs or 69 kV bus) would not fall within the scope of the SAR.

ATC believes the scope of the SAR should only focus on BES dynamic reactive resources similar in nature to the existing BES definition and scope of the existing standards.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 3,5

Answer	No
Document Name	

Comment

AEP objects to the SAR’s scope as currently proposed and find it to be far too open-ended, as typified by the inclusion of “all ***varieties*** of transmission-connected dynamic reactive resources that are utilized in providing ERS in the BES.” While we acknowledge that new technologies in this regard continue to emerge, more specificity is needed within the SAR to enable industry to provide meaningful feedback.

The final paragraph on page 7 of the Whitepaper expresses concern regarding an apparent “significant inconsistency” between the intent of MOD-025-2 to “ensure that accurate information on generator…capability is available for planning models used to assess Bulk Electric System (BES) reliability” and the actual results obtained during testing. The authors of the White Paper believe that misconceptions regarding generator maximum achievable reactive capability may be causing the provision of incorrect data for the purposes of MOD-032-1, driven by the requirements of MOD-025. The SAR would presumably require more robust testing on transmission-connected dynamic reactive resources, and it must be understood and acknowledged by the SDT that such testing would differ greatly from that of the generation resources currently in scope. We have provided feedback below regarding how we believe such testing impacts the standards that are in scope for this project.

MOD-026: While initial testing is reasonable, it is not realistic to perform any ongoing dynamic testing of FACTS devices after they are installed on the system. FACTS devices are dynamically tested on a RTDS simulator in the lab before field commissioning, and against the actual system during field commissioning. Results of these tests are used to validate the models provided. It is not expected that dynamic response would change on an inverter based system after initial design, thereby making subsequent tests irrelevant.

MOD-027: This standard does not apply to FACTS voltage control equipment, though it could apply to HVDC tie equipment. Frequency response and power flow contingency settings are an optional characteristic available in most manufacturers’ control systems and is not be utilized by all entities. These power flow and frequency response capabilities are tested as part of the factory testing before the unit is commissioned to insure that the capability performs correctly. No further verification is needed on HVDC equipment unless the frequency response capability is turned on and put into production.

PRC-019: Initial factory testing is sufficient, and no ongoing field testing is necessary. Factory coordination of protection elements and controls is a basic part of the design of a FACTS device. When possible, FACTS devices are tested to the full range of operation during commissioning, otherwise such testing is always performed on the RTDS during factory testing. Test results are then compiled and made available to show compliance with specifications. If changes are made in the field, then coordination studies would be required to update the documentation.

PRC-024: Once again, initial factory testing is sufficient, and no ongoing field testing is necessary. Protective relays are coordinated with the operation of the FACTS device during the design phase. The FACTS control system is operated against the RTDS model of the system during factory testing to insure that all specified transient phenomena are properly handled by the device. Many tests are run at varying voltages and frequencies to prove that the device is robust and meets standards. Test results are compiled and made available to show compliance with specifications. If changes are made in the field then coordination studies would be required to update the documentation.

Mod-025: The testing of a FACTS reactive resource may potentially (though obviously unintentionally) introduce risk to the system to which it is connected. Operating the system outside reasonable parameters is not acceptable for the purposes of testing. Testing of a FACTS reactive resource will be limited due to the constraints of the system at the time the testing is performed. It is quite possible that full output may not be obtained in either the capacitive or inductive direction (or both). Testing cannot require the disruption of the power system in the vicinity of the FACTS device, nor can it put that system at any risk due to the testing. The reason for the termination of the test at any output level should be documented in the test results with no further requirements due for further testing. As mentioned in the last paragraph of the white paper, an early termination of a test due to system constraints at the time of the test should not be construed to mean that the unit will always be limited to that maximum output. Any resulting limitation of the FACTS device in planning models would need to be determined after analysis of the cause of the limitation in the test results.

In summary, while AEP agrees (at least in part) with what the SAR seeks to achieve, we do not see a true reliability-driven need for standards on these suggested devices, certainly not to the extent as for independent generators. The existence and usage of these additional devices, by their very nature, requires their owners to perform reliability studies, calculations, and take other necessary measures to verify both their proper operation and modeling. As a result, we do not believe that adding obligations for these devices would perceptibly enhance the reliability of the BES, and would primarily be administrative in nature. We do not believe a “reliability parity” exists between the newly-suggested devices and those already within the scope of these standards, and do not believe that the standards should be revised to include these additional devices. However, if the SDT does indeed pursue such changes, we believe the SDT should revise the SAR to address the following a) pursue device-specific obligations for the newly-proposed non-generation devices, b) ensure that Violation Severity Levels for any new obligations are less than those associated with the existing obligation for Facilities comprising generation resources and c) ensure that the periodicity associated with the obligations on the additional devices are less burdensome as well.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1 - MRO

Answer	No
Document Name	

Comment

MPC supports comments from the MRO NERC Standards Review Forum (NSRF).

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer	No
Document Name	

Comment

ACES has three main concerns with the proposed SAR:

1. The definition of Essential Reliability Services (ERS) is not consistent amongst the SAR, the White Paper, and other previous resources.

- The SAR states the following: Dynamic reactive resources used to provide Essential Reliability Services (ERS) in the BES include generation resources (rotating machine and inverter-based) as well as transmission connected dynamic reactive resources (power-electronics based).
- The SAMS White Paper states the following: ... essential reliability services (ERS) such as voltage control, frequency control, and ramping/balancing capability.
- The Essential Reliability Services “Tutorial” form 2014 explains Essential Reliability Services as an integral part of reliable operations to assure the protection of equipment and are the elemental “reliability building blocks” provided by generation. That includes voltage support and frequency support.

Therefore, use of “ERS” requires a NERC-approved definition to avoid any inconsistencies.

2- The Assessment of Applicability in Reliability Standards White Paper that has been supplied as a basis for this SAR is in a draft form. The submission of this SAR should be deferred until the final White Paper is published.

3- The SAR states that the Cost Impact Assessment is unknown. Cost Impacts are an important aspect to be studied. Company budget cycles are requested to be measured as a consideration in the time-extension decisions.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6

Answer	No
Document Name	

Comment

AZPS proposes the scope be modified to include "BES" connected dynamic reactive devices instead of "transmission" connected reactive devices as not all devices connected at the transmission level are applicable to the BES. In addition, there are cases where devices connected at 69kV may be considered BES.

AZPS does not agree with all of the conclusions in the February 2019 NERC SAMS White Paper. For example, on Page 2, Table 1: Applicability of Relevant NERC Reliability Standards to Dynamic Reactive Resources, APS does not agree with the conclusion that LCC HVDC is applicable to MOD-027 or that VSC HVDC is applicable to MOD-025, MOD-026 or MOD-027. The intent of MOD-026 is to verify excitation system model and the intent of MOD-027 is to verify turbine generator model. Application of these standards to HVDC will not be appropriate. If the intent is to verify HVDC dynamic models as used in powerflow and stability studies, AZPS asserts that there should be a separate SAR for that requirement.

On Page 7, Other Considerations, Item 2 of the NERC SAMS White Paper additional complications of MOD-025 are discussed.

"NERC SAMS and the NERC Power Plant Modeling and Verification Task Force (PPMVTF) have both identified a significant inconsistency between the intent of MOD-025-2 to "ensure that accurate information on generator and synchronous condenser reactive power capability is available for planning models used to assess Bulk Electric System (BES) reliability" and the actual results obtained during testing. MOD-025-2 does not require the full (maximum achievable) reactive capability of the resource to be reached via test. This is warranted because the testing conditions likely will limit the resource from reaching its full (maximum achievable) reactive capability before other limits are reached such as system voltage, generator terminal voltage, or auxiliary bus voltage limits. While this is reasonable for testing, the standard does not require calculations to be performed to prove that the resource could reach its full (maximum achievable) reactive capability under more favorable operating conditions (i.e. when that full reactive capability is needed for maintaining voltage schedule). Therefore, there is a significant misconception in the industry that the testing results should be used as the same data submitted for MOD-032-1 for capability of the machine. This misconception is likely leading to incorrect data being supplied for the purposes of MOD-032-1 and is driven by the requirements in MOD-025-2."

AZPS asserts that it is not prudent to modify MOD-025 to include new devices when there are other issues that need to be addressed.

AZPS further notes that there is a discrepancy in the NERC SAMS White Paper as follows: On Page 2, Table 1 indicates that LCC HVDC is recommended to be applicable to PRC-024 but on Page 6, the Technical Basis for Applicability in the White Paper indicates that it should NOT be applicable to PRC-024. AZPS recommends the table should be corrected to have a N/A value.

Likes 0	
Dislikes 0	

Response

Glenn Barry - Los Angeles Department of Water and Power - 1,3,5,6

Answer	No
Document Name	

Comment

The added benefit to reliability might not be significant to justify the inclusion of these transmission-connected resources. Reliability for these resources is currently addressed by Standards such as PRC-004, which requires Misoperations to be analyzed and reported and the development of Corrective Action Plans to remediate issues. In addition, the protection and control systems found in these transmission-connected reactive resources are not easily modified and typically are proprietary, requiring assistance from the manufacturer to change settings and test certain systems. Modifying existing protection and control systems affects warranty and is not recommended. Therefore, there is no need to retest/compare when no modifications are being made to the system. With the loss of a FACTS device, the Power System should not completely fall apart. There may be issues with voltage stability for short periods of time, such as power flow, but the system should not collapse.

Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 3,4,5,6, Group Name NCPA	
Answer	No
Document Name	
Comment	

NO, NCPA does not support this SAR as written.

NCPA feels the SAR needs to clearly state that GO/GOPs will not be subject to any changes to MOD-025, 26, 27 and PRC 19 and 24 Standards due to this Project 2020-02. If the SAR drafting team disagrees please state exactly why members are willing to imply it doesn't impact GO/GOPs but are unwilling to back it up by excluding GO/GOP from the SAR and future subject standards new/modified requirement(s).

As written the SAR seems straight forward. For instance it mentions (non-generation) transmission connected reactive resources, which looks like it excludes GO/GOPs. But from our experience with FERC, NERC, and WECC, unless the SAR or the Standard specifically states it is not applicable to GO/GOPs we are going to have to annually provide documentation/evidence proving that we don't own/operate transmission connected resources and compile evidence, or null evidence letters, annually proving compliance or non-applicability of the standard. This is simply another cost and time burden on NCPA, our investors, members, and customers, with zero reliability benefit.

Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - 1 - SERC	
Answer	No
Document Name	
Comment	

It does not appear that the SAMS seriously considered a Reliability Guideline to address the issues identified in the White Paper. GTC believes that a Reliability Guideline would be a better initial step to address the needs identified in the White Paper without adding the administrative burden/cost of record keeping and documentation for audit purposes; therefore, GTC does not believe that a SAR is necessary at this time.

Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	

Answer	No
Document Name	
Comment	

Dynamic reactive power resources have nothing to do with frequency control, which is a direct consequence of the balance of real power balances between generation and load. We believe that the inclusion of MOD-027 in the list of standards in the SAR is out of order.

PRC-019 already applies to TO-owned synchronous condensers. PRC-019 was originally deemed necessary due to miscoordination of the protection elements embedded in automatic voltage regulating system with the process control limiters which may exist in the controls. Does this miscoordination exist in the additional "all varieties of dynamic reactive resources" scope proposed? In other words, for the additional scoped elements, are the tripping elements tripping before the limiting elements limit? The driving source of need and the impetus for increasing the scope of the PRC-019 applicability is not justified in the SAR.

The detailed description does not provide sufficient detail as to the proposed extent of the modifications to existing requirements, nor does it provide insight into possible function of new requirements. It is suggested that this detail be added to direct a standard drafting team towards the specific concern to be addressed.

MOD-025 already applies to TO-owned synchronous condensers. Proportionately, are there substantial numbers of additional transmission connected reactive power resources that, if modelled, would significantly enhance the validity of a planning model? The driving source of need and the impetus for increasing the scope of the MOD-025 applicability is not justified in the SAR. Additionally, the operational limitations observed during the first 5 years of the MOD-025 testing which yielded test results that did not prove the actual reactive capabilities of the machines under test raise valid questions regarding its value - what is to say that expanding the applicability to additional equipment will yield valuable information on reactive capabilities?

The MVA applicability thresholds for MOD-026 were chosen so that approximately 80% of the connected generation in each interconnection would be drawn into the scope of the applicability. Are there sufficient quantities of other transmission connected reactive power resources whose inclusion in the applicability would significantly impact and enhance the validity of planning models?

It is suggested that the Project Scope statement be modified to limit the applicable resources to those specifically identified by the SAMs white paper. Including a statement such as “all variety of transmission connected dynamic resources is unbounded and could create confusion as to what resources are applicable.

Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes

Document Name	
Comment	

PacifiCorp supports the proposed Standards Authorization Request to revise the “Applicability – Facilities” and “Applicability-Functional Entities” sections in the MOD-025, MOD-026, MOD-027, PRC-019 and PRC-024 reliability standards to include (non-generation) transmission-connected dynamic reactive resources. PacifiCorp also would like to submit a comment for the team members to consider that for MOD-025, testing the full range of large non-generation transmission-connected dynamic reactive devices may not be possible under normal operating conditions. Data from actual disturbances may need to be used to verify the reactive capability of these devices including high speed switching of any associated switched shunt capacitors and/or reactors that are incorporate to extend the range of the dynamic reactive device.

Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	Yes
Document Name	
Comment	

Idaho Power (IPCO) supports the proposed modifications listed in the SAR for NERC Project 2020-02.

Impact to Idaho Power with regard to including synchronous condensers as applicable resources for MOD-026 is anticipated to be minimal. IPCO has performed dynamic system model validation for IPCO-owned synchronous condensers under the WECC Model Validation and Testing Policy. IPCO has PMU and DFR monitoring equipment installed on the IPCO-owned synchronous condensers; thus, model validation for MOD-026 can potentially be performed using disturbance recording data since all the machines have already under gone baseline testing.

Anticipated impact for the addition of synchronous condensers as applicable resources for PRC-024 is minimal to IPCO.

IPCO supports inclusion of the non-generation dynamic reactive resources listed in Table 1 of the NERC SAMS White Paper.

Likes 0	
Dislikes 0	
Response	

John Pearson - ISO New England, Inc. - 2 - NPCC

Answer	Yes
Document Name	
Comment	

With increasing installations of transmission-connected dynamic reactive resources, it is necessary to obtain accurate models of equipment as actually installed and configured to plan and operate the BES.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Accurate models are required for all transmission connected resources.	
Likes 1	DTE Energy - Detroit Edison Company, 3, Barczak Karie
Dislikes 0	
Response	
Spencer Tacke - Modesto Irrigation District - 3,4,6	
Answer	Yes
Document Name	
Comment	

1. As far as adding other reactive or real power source model verification requirements to the NERC MOD Standards, I am OK with that. But I would like to add an expansion of the scope of the existing requirements to include generating resources with less than a 75 MVA rating, and connected at less than 100 KV, per the explanation below.

1. Based on WECC's experience since the Aug. 10, 1996 WSCC (now WECC) System Wide Outage, I would like to suggest that as part of this SAR, we include the expansion of the scope of those generating resources that need to have their dynamic models verified via MOD-026 & MOD-027, to include those single generating units 10 MVA or larger (or an aggregate facility rating of 20 MVA or larger), and connected at 60 kV and above.

The detailed analysis of the Aug. 10, 1996 WSCC System Wide Outage demonstrated the real significance that the smaller generators have in their impact to the transient stability of the WECC Interconnected System. During that Outage, it wasn't until the smaller U.S. Army Corps of Engineers McNary Hydroelectric Generators (each of the 13 units were smaller than 75 MVA) in the Pacific Northwest ran into excitation limits and tripped off-line causing a further and critical voltage sag, that the voltage oscillations on the 500 kV system started, and which eventually led to the complete voltage collapse and blackout of a major portion of the Pacific and Pacific Northwest System. Their excitation systems were modeled incorrectly at the time, and that is why the initial simulation analysis did not predict the actual response of the Interconnected System that occurred (see Transactions on Power Systems, Vol. 14, No. 3, August 1996; "Model Validation for the August 10, 1996 WSCC System Outage"). For this reason, WSCC (WECC) invoked the mandatory Generating Testing and Model Validation Policy, requiring testing of all generators connected at 60 kV and above, and rated at 10 MVA and above (or an aggregate facility rating of 20 MVA or larger). The effectiveness of this Policy was demonstrated by the analysis of subsequent system wide disturbances that demonstrated good matches between the simulated responses and the actual systems response during the disturbances (see "Generating Unit Model Validation: WECC Lessons and Moving Forward" ; 2009 IEEE Power and Energy Society Meeting, Calgary, AB, Canada, July 26-July 30, 2009). This definitely demonstrated the effectiveness of having accurate generator models for all generators 10 MVA and larger (or an aggregate facility rating of 20 MVA or larger), and connected at 60 kV and above.

In addition, a final and nearly exact match did not occur for the 1996 Outage simulations until the load of the WECC Interconnected System (typically placed on 69 kV and below modeled busses) was more accurately modeled by introducing a 20% induction motor load, along with the traditional static load previously modeled. This fact also demonstrated the extreme importance the lower voltage connected models have on the overall system response of the WECC high voltage (i.e., greater than or equal to 100 kV) Interconnected System.

And in recent years with the very large influx of renewable generation (many thousands of MWs) in California being added to the WECC System at the lower levels of 20 MVA and connected at 69 kV and below, it is even more incumbent on us to include in model testing and validation, these smaller size generating units.

Thank you.

Sincerely,

Spencer Tacke

Senior Electrical Engineer

Modesto Irrigation District

1231 11th Street, Modesto, CA 95354

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer	Yes
Document Name	
Comment	
Please see comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
It is recommended that the drafting team consider working with industry vendors of transmission connected nonsynchronous sources (i.e. FACTS, HVDC) to ensure that the standard requirements can be benchmarked with actual and realistic resource testing capabilities and modeling capabilities. As mentioned in the White Paper, controls for nonsynchronous sources are different based on the types of equipment technologies used in the different devices. In terms of dynamic simulation modeling of nonsynchronous sources (i.e. FACTS, HVDC), it is expected that such dynamic models would be developed by and provided by the device vendor. It is encouraged that the applicable standards promote the development of, and use of, standardized "off the shelf" dynamic simulation software models. It is likely that many Transmission Owners (TOs) rely on the services of the nonsynchronous resource (i.e. FACTS, HVDC) vendor for capability testing, protection coordination and model verification – due to the specialized nature of these resources. The proposed standards development envisioned by this SAR would likely increase a TO's reliance on support services from their nonsynchronous resource vendors, with a corresponding increase in costs.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Westar Energy - 1,3,5,6 - MRO, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	

Westar Energy and Kansas City Power & Light, Evergy companies, incorporate by reference and support the Edison Electric Institute (EEI) response to Question 1.

Likes 0	
Dislikes 0	

Response
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment
EEI supports the proposed changes contained in the Project 2020-02 SAR. The SAR, which is supported by a comprehensive white paper developed by the System Analysis and Modeling Subcommittee (SAMS), identifies a gap in the existing body of Reliability Standards that has been created by the changing resource mix and changes in technology and transmission connected devices that are needed to support BES reliability. EEI agrees with SAMS that both rotating machines and power-electronics based resources that are capable of supporting Essential Reliability Services (ERS) should do so in a consistent manner.

Likes 0	
Dislikes 0	

Response
Daniel Gacek - Exelon - 1,3,5,6

Answer	Yes
Document Name	

Comment
Exelon agrees with the proposed scope as described in the SAR and concurs with the comment submitted by EEI.

Likes 0	
Dislikes 0	

Response
Quintin Lee - Eversource Energy - 1,3, Group Name Eversource Group

Answer	Yes
Document Name	

Comment	
The applicability of NERC standards to battery energy storage resources should be considered as some large projects are in development now. The applicability of the NERC standards needs to be noted for both storing and releasing energy.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
I agree with the recommendation. Dynamic reactive resources, including generation resources such as rotating machinery as well as transmission connected dynamic reactive resources, both in the form of rotating machinery such as synchronous condensers, and power-electronics based devices such as SVC's and STATCOMS, affect the transmission voltages, power transfer levels and hence the reliability of the power system due to their ability to generate and absorb Mvars dynamically and in the steady state. In many cases the MVA rating of these devices can be larger than single generating units. As such the accurate representation and capability testing of such devices will contribute to the overall reliability of the BES.	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - NPCC - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
Please consider revising the proposed scope to only include the transmission-connected dynamic reactive resources that are referenced in the SAMs white paper. This suggested revision would align with the detailed description of the SAR.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA believes this is a timely and much needed effort to ensure transmission-connected reactive resources have validated dynamic models, and appropriate system performance. The Western Interconnection is undergoing significant transformation with its generation mix. Many of the large coal-fired and nuclear power plants have retired or are scheduled to retire. These generators are replaced with renewable plants, which are usually smaller in size. Current 75 MW threshold represented 80% of generating capacity in the Western Interconnection in 2007. However, with the retirement of large synchronous generators and addition of smaller renewable plants, the threshold is now lower. As such, BPA requests the drafting team to revisit the applicability threshold in MOD-026/27 Reliability Standards for the Western Interconnection as additional scope to this SAR.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

ERCOT generally supports the concept described in the SAR. Regarding PRC-024 only, ERCOT agrees that the standard should be revised to prohibit tripping of GO-owned reactive devices outside certain defined parameters, as suggested by the SAMS whitepaper, but does *not* agree that the standard should be revised to prohibit tripping of TO-owned reactive devices. This is because, to the extent tripping of such devices outside of PRC-024's defined parameters can foreseeably cause a reliability issue, that issue should be identified in a TP's or PC's annual Planning Assessment and resolved through a Corrective Action Plan (CAP). To the extent the tripping of a TO-owned reactive device does not result in a violation of planning criteria, then requiring the TO to prevent the tripping of that device in conformance with the settings of PRC-024 would not be necessary or cost-effective.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - Black Hills Power - 1,3,5,6 - MRO,WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
MISO supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	

MISO supports the intent of the SAR to augment the applicability of existing reliability standards for verifying the capability, modeling and performance of dynamic reactive resources to include (non-generation) transmission-connected reactive resources; however, as written the scope of the SAR relies on the definition of Essential Reliability Services (ERS) and the definition of ERS is unclear.

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE appreciates the SAR drafting team's efforts in addressing reliability and issues we have seen as a contributing cause to past events (e.g. STATCOM tripping off during voltage excursion during July 2015 event). Texas RE noticed, however, that the scope of the SAR focuses on "transmission-connected resources", but does not clearly address how these reactive devices will be addressed when owned by the Generator Owner (GO). This is especially pertinent for dispersed power producing resources where synchronous condensers, SVCs, and STATCOMs are frequently located behind the GSU and used to supplement the Reactive Power output of the individual generating units.

For example, Footnote 4 of PRC-024-2 states "*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.*" Since the language in this footnote only addresses generating units, a synchronous condenser, SVC, or STATCOM owned by the GO is not applicable to the currently effective version of the Standard. **Texas RE recommends clarifying the SAR to ensure the modifications to applicability include GO dynamic reactive devices**.

Likes 0	
Dislikes 0	
Response	

2. Provide any additional comments for the SAR drafting team to consider, if desired.	
Ruida Shu - NPCC - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	
Document Name	
Comment	
The SAR drafting team should consider an implementation plan specifically for BES dynamic reactive resources initial MOD/PRC testing and reporting.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
The industry need section of the SAR needs is confusing in listing the GO-owned rotating-machine and inverter-based generating facilities that are already subject to the MOD and PRC standards listed in the SAR title. It is suggested that the need be focused only on the missing elements in the focus of the concern of this SAR. It is unclear what the term non-generation means. It is suggested that the detailed description section of the SAR provide only details of what is being proposed to be changed in the list of standard. The basis and justification references pointing to the SAMS white paper, in our opinion, do not belong in the detailed description section of what is being proposed. More specificity is suggested: e.g."modify the applicability sections to include…, modify requirements, if needed, to address these additional facility types…, modify/create new requirements to achieve specific objectives…, add glossary terms, if needed …".	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1,3,5,6	

Answer	
Document Name	

Comment

1. MH believes that it is important to verify voltage and frequency ride through capability of LCC HVDC links. Given these links are large, loss of the links can be impactive to reliability – especially frequency support. Therefore, PRC-024 should be applicable to LCC links.

While the SAR is clearly focused on “reactive power resources” they’re missing an important contribution of LCC HVDC to frequency stability. The scope of the SAR should clearly address both voltage and frequency.

On page 6 of the NERC SAMS White paper it says the following for PRC-024:

“The LCC HVDC would be expected to ride through grid voltage and frequency excursion events to provide continuity of service (i.e. maintaining MW output). Therefore, PRC-024 should not be applicable to LCC HVDC”.

This statement contradicts with the SAMS recommendation in Table-1 to include LCC HVDC in PRC-024. NERC should revise this White Paper to ensure that PRC-024 is applicable to LCC HVDC.

2. MH believes MOD-25 should be applicable to LCC HVDC as well. From model verification point of view, it is important to know the behavior (MW/MVAr) over the range of operation at the inverter bus.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

As more utilities begin to use PV plants as dynamic reactive power sources at night when real power is zero, it is increasingly important that this unique mode of operation is considered as the subject reliability standards are revised. In particular, MOD-025 should have provisions for reactive power capability at zero power for inverter-based resources that are capable of such operation.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 1,3,6

Answer	
Document Name	

Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3, Group Name Eversource Group	
Answer	
Document Name	
Comment	
Additionally the NERC standards applicability to all energy storage (compressed air, flywheel, gravitational, etc.) methodologies should be considered. The applicability of the NERC standards needs to be noted for both storing and releasing energy.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
There appears to be a typo on page 6 where the SAR states: “Therefore, PRC-024 should not be applicable to LCC HVDC.” Table 1 of the document indicates the SAMS recommendation is for PRC-024 to be applicable to LCC HVDC, and the statement on page 6 that “The LCC HVDC would be expected to ride through grid voltage and frequency excursion events to provide continuity of service” indicates the intent of the SAR is for PRC-024 to be applicable to LCC HVDC.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1,3,5,6	
Answer	
Document Name	

Comment	
Exelon concurs with the comment submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

While EEI supports the proposed SAR, we offer the following suggestions to ensure the project is appropriately bounded.

1. EEI suggests that the Project Scope statement be modified to limit the applicable resources to those specifically identified by the SAMs white paper.

2. While EEI supports and agrees with the finding of the SAMs white paper identified in the Consensus Building Activity section of the SAR, we disagree that the white paper qualifies as a “consensus” report given it was not vetted broadly by the Industry EEI suggest this statement be removed.

EEI also offer the following non-substantive comments for the SAR:

1. EEI suggests modifying the title of this SAR to “Modification of MOD-025, MOD-026, MOD-027, PRC-019 and PRC-024 to include Dynamic Reactive Resources.”

2. In the section that identifies Standards and SARs that should be referenced, EEI suggests that the PRC-024 SAR reference should be changed to include a reference to the BOT approved PRC-024-3 Reliability Standard. Additionally, since the PRC-019 SAR has not yet been approved by the Standards Committee, EEI suggests this reference be removed.

Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	

MISO supports comments submitted by the MRO NSRF and recommends the following clarifications to the scope of the SAR:

Implementation Plan – include the development of an implementation Plan for the initial testing and reporting of dynamic reactive resources newly introduced under the applicability of revised standards.

Definition of Essential Reliability Services (ERS) – define Essential Reliability Services (ERS) as the description of ERS has varied over time and includes some definitions which limit the focus to generation and demand resources. Examples provided below.

· The Essential Reliability Services Task Force (ERSTF) Scope Document approved by the NERC Planning and Operating Committees on March 5, 2014 defines Essential Reliability Services as "the elemental 'reliability building blocks' from resources (generation and demand) necessary to maintain Bulk Power System (BPS) reliability. ERS are operational attributes from conventional generation, such as providing reactive power to maintain system voltages and physical inertia to maintain system frequency, necessary to reliably operate the BPS."

http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Scope_ERSTF_Final.pdf

· The October 2014 NERC Essential Reliability Services Task Force White Paper "*A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability*" explains Essential Reliability Services as: "ERSs are an integral part of reliable operations to assure the protection of equipment, and are the elemental "reliability building blocks" provided by generation" including voltage support and frequency support.

· The February 2019 NERC SAMS White Paper, "*Transmission Connected Dynamic Reactive Resources and HVDC Equipment – Assessment of Applicability in Reliability Standards,"* referenced in the SAR states: "…essential reliability services (ERS) such as (emphasis added) voltage control, frequency control, and ramping/balancing capability."

Likes 0	
Dislikes 0	

Response

Douglas Webb - Westar Energy - 1,3,5,6 - MRO, Group Name Westar-KCPL

Answer	
Document Name	

Comment

Westar Energy and Kansas City Power & Light, Evergy companies, incorporate by reference and support the Edison Electric Institute (EEI) response to Question 2.

Likes 0	
Dislikes 0	

Response

Teresa Cantwell - Lower Colorado River Authority - 1,5

Answer	
Document Name	

Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - 1 - SERC	
Answer	
Document Name	
Comment	
If the SAR is to be accepted, GTC recommends the scope be modified as follows to address the specific concern of non-generation, transmission-connected dynamic reactive resources: Revise the “Applicability – Facilities” section, “Applicability – Functional Entities” section, and Requirements (including applicable attachments) in MOD-025, MOD-026, MOD-027, PRC-019 and PRC-024 reliability standards to comprehensively address all varieties of ***(non-generation)*** transmission-connected dynamic reactive resources that are utilized in providing ERS in the BES.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 3,4,5,6, Group Name NCPA	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	

Document Name	
Comment	

AZPS recommends defining what qualifies as a "dynamic reactive resource" within the Glossary of Terms Used in NERC Reliability Standards. AZPS believes that without a definition there could be a gap in the applicability of the standard. AZPS suggests that the criteria listed on Slide 12 of "Dynamic vs. Static Resources" from the March 2017 Industry Webinar for Reactive Power Planning, NERC System Analysis and Modeling Subcommittee (SAMS) should be used as a starting point for the development of the definition.

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
- Maintain set point voltage or operate in voltage droop mode
- Many are power electronics ballots
- Can respond within electrical cycles using fast-acting controls.

AZPS suggests that the drafting team review the periodic performance of each device type within MOD-025 and recommends that the frequency be no more than every ten years.

Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer	
Document Name	
Comment	

Please see comments submitted by Edison Electric Institute.

Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer	
Document Name	
Comment	

Thank you for the opportunity to provide comments.

Likes 0	
Dislikes 0	

Response

Spencer Tacke - Modesto Irrigation District - 3,4,6

Answer	
Document Name	

Comment

1. Based on WECC's experience since the Aug. 10, 1996 WSCC (now WECC) System Wide Outage, I would like to suggest that as part of this SAR, we include the expansion of the scope of those generating resources that need to have their dynamic models verified via MOD-026 & MOD-027, to include those single generating units 10 MVA or larger (or an aggregate facility rating of 20 MVA or larger), and connected at 60 kV and above.

The detailed analysis of the Aug. 10, 1996 WSCC System Wide Outage demonstrated the real significance that the smaller generators have in their impact to the transient stability of the WECC Interconnected System. During that Outage, it wasn't until the smaller U.S. Army Corps of Engineers McNary Hydroelectric Generators (each of the 13 units were smaller than 75 MVA) in the Pacific Northwest ran into excitation limits and tripped off-line causing a further and critical voltage sag, that the voltage oscillations on the 500 kV system started, and which eventually led to the complete voltage collapse and blackout of a major portion of the Pacific and Pacific Northwest System. Their excitation systems were modeled incorrectly at the time, and that is why the initial simulation analysis did not predict the actual response of the Interconnected System that occurred (see Transactions on Power Systems, Vol. 14, No. 3, August 1996; "Model Validation for the August 10, 1996 WSCC System Outage"). For this reason, WSCC (WECC) invoked the mandatory Generating Testing and Model Validation Policy, requiring testing of all generators connected at 60 kV and above, and rated at 10 MVA and above (or an aggregate facility rating of 20 MVA or larger). The effectiveness of this Policy was demonstrated by the analysis of subsequent system wide disturbances that demonstrated good matches between the simulated responses and the actual systems response during the disturbances (see "Generating Unit Model Validation: WECC Lessons and Moving Forward" ; 2009 IEEE Power and Energy Society Meeting, Calgary, AB, Canada, July 26-July 30, 2009). This definitely demonstrated the effectiveness of having accurate generator models for all generators 10 MVA and larger (or an aggregate facility rating of 20 MVA or larger), and connected at 60 kV and above.

In addition, a final and nearly exact match did not occur for the 1996 Outage simulations until the load of the WECC Interconnected System (typically placed on 69 kV and below modeled busses) was more accurately modeled by introducing a 20% induction motor load, along with the traditional static load previously modeled. This fact also demonstrated the extreme importance the lower voltage connected models have on the overall system response of the WECC high voltage (i.e., greater than or equal to 100 kV) Interconnected System.

And in recent years with the very large influx of renewable generation (many thousands of MWs) in California being added to the WECC System at the lower levels of 20 MVA and connected at 69 kV and below, it is even more incumbent on us to include in model testing and validation, these smaller size generating units.

Thank you.

Sincerely,

Spencer Tacke

Senior Elelctrical Engineer

Modesto Irrigation District

1231 11th Street, Modesto, CA 95354

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1 - MRO

Answer	
Document Name	

Comment

MPC supports comments from the MRO NERC Standards Review Forum (NSRF).

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	
Document Name	

Comment

The Standard Draft Team should consider and implement a MVAR/MVA size threshold for validation of the dynamic reactive resources along with clarifying the BES/Non-BES discussion above.

Likes 0	
Dislikes 0	

Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	
Document Name	
Comment	

Reclamation recommends the SAR drafting team thoughtfully assess the cost impacts associated with this SAR to effect changes in a cost-effective manner. The SAR proposes a significant increase in the scope of the affected standards, which will have a substantial impact on affected entities and should not be taken without appropriate consideration.

Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments".

The use of the wording "Essential Reliability Services (ERS)" requires a NERC approved definition. There are many different pseudo explanations of what Essential Reliability Services are.

- From the 3 Nov 2014 Essential Reliability Services "Tutorial" which explains Essential Reliability Services as ERSs are an integral part of reliable operations to assure the protection of equipment and are the elemental "reliability building blocks" provided by generation. That include voltage support and frequency support.
- The SAMS White Paper states (within this SAR) "…essential reliability services (ERS) such as (emphasis added) voltage control, frequency control, and ramping/balancing capability".
- This SAR states "Dynamic reactive resources used to provide Essential Reliability Services (ERS) in the BES include generation resources (rotating machine and inverter-based) as well as transmission connected dynamic reactive resources (power-electronics based).

With the above inconsistency of what ERS is, the SAR should include the development of an Essential Reliability Services definition.

Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2 - NPCC	

Answer	
Document Name	
Comment	
The SAR drafting team should consider an implementation plan specifically for BES dynamic reactive resources initial MOD/PRC testing and reporting.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	

Comment	
The SAR drafting team should consider an implementation plan specifically for BES dynamic reactive resources initial MOD/PRC testing and reporting.	
Likes 0	
Dislikes 0	
Response	

Project 2020-02 Transmission-connected Dynamic Reactive Resources

Summary Response to SAR Comments | February 2022

Introduction

The Standard Authorization Request (SAR) drafting team thanks all who provided comments during the informal comment period. All comments received were reviewed and the identified common themes are addressed below. Some comments have been reserved for consideration during the standard drafting phase of the project, including the financial impact question and risk.

1. **TCDRR definition(s) and Applicability section in standards should be clear which assets or technologies are considered a TCDRR and what is applicable within each Reliability Standard.**
   The Project 2020-02 standard drafting team (SDT) will use the definition of terms, revise applicability section(s), and revise standard language to make clear what assets/technologies are considered a transmission-connected dynamic reactive resource (TCDRR), and may define specific technologies (SVC, STATCOM, FACTS, HVDC, etc.). The SAR allows the SDT to add, modify or retire Glossary terms.

2. **The SDT should coordinate drafting a Reliability Guideline with a NERC technical committee rather than revising the standards.**
   Though there is an existing *Reliability Guideline: Reactive Power Planning (December 2016)* covering reactive power planning and related issues, there is currently not a Reliability Guideline drafted or being drafted that addresses the reliability risks outlined in the SAR or in SAMS white paper, *Transmission Connected Dynamic Reactive Resources – Assessment of Applicability in Reliability Standards*. The 2020-02 SDT is tasked with determining whether revisions to the standards will appropriately address the reliability risk outlined in the SAR and white paper.

3. **The SDT should consider defining addition terms such as essential reliability services.**
   The SAR allows the creation of new Glossary terms as part of the project scope. This can include new Glossary terms for all or some of the TCDRR noted in the SAMS white-paper. Essential reliability services is currently not a defined term in the Glossary of Terms used in NERC Reliability Standards. The SDT may consider adding new terms, such as essential reliability services, if they find it necessary as part of the project.

4. **Dynamic reactive resources located at a generation Facility should not be considered TCDRR.**
   The SAR DT agrees with this comment. When a dynamic reactive resource (e.g. FACTS device or synchronous condenser) is located at a generation Facility, the asset would be covered under the applicability of existing standards. As described in the SAR, Project 2020-02 is meant to address non-generation TCDRR under the purview of the Transmission Owner. The SDT will attempt to make this distinction clear, either in the Applicability section of revised standards or in Glossary term(s).

5. **The SDT should determine the practicality of staged testing TCDRR as part of MOD-025, MOD-026, and MOD-027 implementation before revising the standards.**
   Modeling data for synchronous condensers, FACTS and HVDC equipment is provided by the Transmission Owner to Transmission Planners & Planning Coordinators as part of MOD-032. However, the models are not subsequently validated, unless being reviewed by the Transmission Planner as part of MOD-033 following a system disturbance. MOD-025/026/027 could provide a means for the Transmission Owner to validate the models using a staged test, or verify the model(s) reflect in-service equipment by an alternate means. The Project 2020-02 SDT will coordinate and advise the SDTs for Project 2020-06 (MOD-026/027) & Project 2021-01 (MOD-025 and PRC-019) on the practicality of performing staged testing. However, the decision of whether and how to revise MOD-025, MOD-026, MOD-027 to include TCDRR will reside with those respective drafting teams.

Resources

- Project 2020-02 Transmission-connected Reactive Dynamic Resources
- TCR SAR (MOD-026, MOD-027, MOD-025, PRC-019, PRC-024)
- Industry Comments

Unofficial Nomination Form

Project 2020-02 Transmission-connected Dynamic Reactive Resources Standard Authorization Request Drafting Team

Do not use this form for submitting nominations. Use the electronic form to submit nominations for Standard Authorization Request (SAR) drafting team members by **8 p.m. Eastern, Monday, May 17, 2021.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Chris Larson (via email), or at 404-446-9708.

Background

The problem of increasing amounts of reactive power being supplied by nonsynchronous sources was identified in NERC's 2017 Long-term Reliability Assessment. In response to the concern, the Planning Committee (PC) assigned the System Analysis and Modeling Subcommittee (SAMS) to study the issue. The SAMS developed the *Applicability of Transmission-Connected Reactive Devices* white paper, which was approved by the PC at its December 10-11, 2019 meeting. The PC Executive Committee reviewed the draft SAR from SAMS at its January meeting and subsequently approved the SAR by email vote ending on February 11, 2020. The SAR concerning Transmission-Connected Resources (TCR) aims to modify NERC Reliability Standards MOD-025, MOD-026, MOD-027, PRC-019 and PRC-024 to comprehensively include all types of dynamic reactive resources (including static var systems and FACTS) and DC transmission systems used to provide Essential Reliability Services (ERS) in the Bulk Electric System (BES).

Dynamic reactive resources used to provide ERS in the BES include generation resources (rotating machine and inverter-based) as well as transmission connected dynamic reactive resources (power-electronics based). Existing Reliability Standards for verifying the capability, modeling and performance of dynamic reactive resources are only applicable to Facilities comprising generation resources. Augmenting the applicability of these standards to include (nongeneration) transmission-connected reactive resources, both rotating machine (i.e. synchronous condenser) and power-electronics based, will enhance the BES reliability by ensuring that the capability, models and performance are verified and validated for all varieties of dynamic reactive resources utilized in providing ERS in the BES.

Standard(s) affected: PRC-024. MOD-025, MOD-026, MOD-027, PRC-019 revisions will be coordinated with other project teams.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls. The time commitment for this project is expected to be one face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed upon timeline the team sets forth. Face-to-face meetings will be conducted only when CDC health guidelines permit. Team members may also have side projects, either individually or by sub-group, to present for discussion and review. Lastly, an important component of the team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful ballot. Previous drafting team experience is beneficial but not required. See the project page and nomination form for additional information.

NERC is seeking individuals who possess experience in the following areas:

- Developing and verifying dynamic models used in long-term planning assessments, specifically for transmission-connected reactive resources*
- Modeling and studying transmission-connected reactive devices during interconnection studies or long-term planning assessments
- Performing equipment capability testing for transmission-connected reactive devices and rotating machines
- Understanding the large disturbance behavior of transmission-connected reactive devices, particularly the power electronic controls that govern the performance of these devices during abnormal grid conditions

* Transmission-connected reactive resources generally refers to FACTS (Flexible AC Transmission System) devices such as Static Var Compensators (SVCs) and Static Synchronous Compensator (STATCOMs) as well as other power-electronic devices that fall in this category such as HVDC circuits and synchronous condensers.

Name:	
Organization:	
Address:	
Telephone:	
Email:	
Please briefly describe your experience and qualifications to serve on the requested SAR Drafting Team (Bio):	

If you are currently a member of any NERC drafting team, please list each team here: ☐ Not currently on any active SAR or standard drafting team. ☐ Currently a member of the following SAR or standard drafting team(s):
If you previously worked on any NERC drafting team please identify the team(s): ☐ No prior NERC SAR or standard drafting team. ☐ Prior experience on the following team(s):
Acknowledgement that the nominee has read and understands both the *NERC Participant Conduct Policy* and the *Standard Drafting Team Scope* documents, available on NERC Standards Resources. ☐ Yes, the nominee has read and understands these documents.

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:		
☐ MRO ☐ NPCC ☐ RF	☐ SERC ☐ Texas RE ☐ WECC	☐ NA – Not Applicable

Select each Industry Segment that you represent:	
☐	1 — Transmission Owners
☐	2 — RTOs, ISOs
☐	3 — Load-serving Entities
☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	6 — Electricity Brokers, Aggregators, and Marketers
☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users
☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:	
☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		Email:	
Name:		Telephone:	
Organization:		Email:	

Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Standards Announcement

Project 2020-02 Transmission-connected Dynamic Reactive Resources

Supplemental Nomination Period Open through May 17, 2021

Now Available

Additional nominations are being sought for Standard Authorization Request (SAR) drafting team members through **8 p.m. Eastern, Monday, May 17, 2021**.

Use the electronic form to submit a nomination and contact Wendy Muller regarding issues with the system. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

Background

The potential risk of increasing amounts of reactive power being supplied by nonsynchronous sources was identified in *NERC's 2017 Long-term Reliability Assessment*. In response to the concern, the Planning Committee (PC) assigned the System Analysis and Modeling Subcommittee (SAMS) to study the issue. The SAMS developed the *Applicability of Transmission-Connected Reactive Devices* white paper, which was approved by the PC at its December 2019 meeting. The PC Executive Committee reviewed the draft SAR from SAMS at its January meeting and subsequently approved the SAR by email vote ending on February 11, 2020. The SAR was posted for industry comment March 30 – May 13, 2020, and drafting team member nominations were solicited. However, the project was temporarily paused before a SAR drafting team was appointed.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls. The time commitment for this project is expected to be one face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed upon timeline the team sets forth. Face-to-face meetings will be conducted only when CDC health guidelines permit. Team members may also have side projects, either individually or by sub-group, to present for discussion and review. Lastly, an important component of the team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful ballot. Previous drafting team experience is beneficial but not required. See the project page and nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the drafting team in June or July, 2021. Nominees will be notified shortly after they have been appointed.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Chris Larson (via email) or at 404-446-9708. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2020-02 Transmission-connected Dynamic Reactive Resources observer list” in the Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Unofficial Nomination Form

Project 2020-02 Transmission-connected Dynamic Resources

Do not use this form for submitting nominations. Use the electronic form to submit nominations for **Project 2020-02 Transmission-connected Dynamic Reactive Resources** Standard Authorization Request (SAR) drafting team members by **8 p.m. Eastern, Monday, December 20, 2021.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Chris Larson (via email), or at 404-446-9708.

Background

The problem of increasing amounts of reactive power being supplied by nonsynchronous sources was identified in NERC's 2017 Long-term Reliability Assessment. In response to the concern, the Planning Committee (PC) assigned the System Analysis and Modeling Subcommittee (SAMS) to study the issue. The SAMS developed the *Applicability of Transmission-Connected Reactive Devices* white paper, which was approved by the PC at its December 10-11, 2019 meeting. The PC Executive Committee reviewed the draft SAR from SAMS at its January meeting and subsequently approved the SAR by email vote ending on February 11, 2020. The SAR concerning transmission-connected dynamic reactive resources (TCDRR) aims to modify NERC Reliability Standards MOD-025, MOD-026, MOD-027, PRC-019 and PRC-024 to comprehensively include all types of dynamic reactive resources (including static var systems and FACTS) and DC transmission systems used to provide Essential Reliability Services (ERS) in the Bulk Electric System (BES).

Dynamic reactive resources used to provide ERS in the BES include generation resources (rotating machine and inverter-based) as well as transmission connected dynamic reactive resources (power-electronics based). Existing Reliability Standards for verifying the capability, modeling and performance of dynamic reactive resources are only applicable to Facilities comprising generation resources. Augmenting the applicability of these standards to include (nongeneration) transmission-connected dynamic reactive resources, both rotating machine (i.e. synchronous condenser) and power-electronics based, will enhance the BES reliability by ensuring that the capability, models and performance are verified and validated for all varieties of dynamic reactive resources utilized in providing ERS in the BES.

Standard(s) affected: PRC-024, MOD-025, MOD-026, MOD-027, PRC-019 revisions will be coordinated with other project teams.

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NERC is seeking individuals who possess experience in the following areas:

- Developing and verifying dynamic models used in long-term planning assessments, specifically for transmission-connected reactive resources*
- Modeling and studying transmission-connected reactive devices during interconnection studies or long-term planning assessments
- Performing equipment capability testing for transmission-connected reactive devices and rotating machines
- Understanding the large disturbance behavior of transmission-connected reactive devices, particularly the power electronic controls that govern the performance of these devices during abnormal grid conditions

* Transmission-connected reactive resources generally refers to FACTS (Flexible AC Transmission System) devices such as Static Var Compensators (SVCs) and Static Synchronous Compensator (STATCOMs) as well as other power-electronic devices that fall in this category such as HVDC circuits and synchronous condensers.

Name:	
Organization:	
Address:	
Telephone:	
Email:	
Please briefly describe your experience and qualifications to serve on the requested SAR Drafting Team (Bio):	

If you are currently a member of any NERC drafting team, please list each team here: ☐ Not currently on any active SAR or standard drafting team. ☐ Currently a member of the following SAR or standard drafting team(s):
If you previously worked on any NERC drafting team please identify the team(s): ☐ No prior NERC SAR or standard drafting team. ☐ Prior experience on the following team(s):
Acknowledgement that the nominee has read and understands both the *NERC Participant Conduct Policy* and the *Standard Drafting Team Scope* documents, available on NERC Standards Resources. ☐ Yes, the nominee has read and understands these documents.

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:		
☐ MRO ☐ NPCC ☐ RF	☐ SERC ☐ Texas RE ☐ WECC	☐ NA – Not Applicable

Select each Industry Segment that you represent:	
☐	1 — Transmission Owners
☐	2 — RTOs, ISOs
☐	3 — Load-serving Entities
☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	6 — Electricity Brokers, Aggregators, and Marketers
☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users
☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:	
☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		Email:	
Name:		Telephone:	
Organization:		Email:	

Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Standards Announcement

Project 2020-02 Transmission-connected Dynamic Reactive Resources

Supplemental Nomination Period Open through December 20, 2021

Now Available

Nominations are being sought for additional Standard Authorization Request (SAR) drafting team members through **8 p.m. Eastern, Monday, December 20, 2021**.

Use the electronic form to submit a nomination and contact Wendy Muller with any issues. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

Background

The potential risk of increasing amounts of reactive power being supplied by nonsynchronous sources was identified in *NERC's 2017 Long-term Reliability Assessment*. In response to the concern, the Planning Committee (PC) assigned the System Analysis and Modeling Subcommittee (SAMS) to study the issue. The SAMS developed the *Applicability of Transmission-Connected Reactive Devices* white paper, which was approved by the PC at its December 2019 meeting. The PC Executive Committee reviewed the draft SAR from SAMS at its January meeting and subsequently approved the SAR by email vote ending on February 11, 2020. The SAR was posted for industry comment March 30 – May 13, 2020, and drafting team member nominations were solicited.

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Next Steps

The Standards Committee is expected to appoint supplemental members to the drafting team in February 2022. Nominees will be notified shortly after they have been appointed.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Chris Larson (via email) or at 404-446-9708. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2020-02 Transmission-connected Dynamic Reactive Resources observer list” in the Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Revision of relevant Reliability Standards to include applicability of transmission-connected dynamic reactive resources		
Date Submitted:	February 24, 2020 (Revised on February 3, 2022)		
SAR Requester			
Name:	Hari Singh – Chair, System Analysis & Modeling Subcommittee (SAMS) (Revised by Project 2020-02 SAR DT)		
Organization:	Xcel Energy		
Telephone:	303-571-7095	Email:	hari.singh@xcelenergy.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
Dynamic reactive resources used to provide essential reliability services (ERS) in the BES include generation resources (rotating machine and inverter-based) as well as transmission connected dynamic reactive resources (power-electronics based). Existing reliability standards for verifying the capability, modeling and performance of dynamic reactive resources are only applicable to Facilities comprising generation resources. Augmenting the applicability of these standards to include (non-generation) transmission-connected reactive resources – both rotating machine (i.e. synchronous condenser) and power-electronics based – will enhance the BES reliability by ensuring that the capability, models and performance is verified and validated for all varieties of dynamic reactive resources utilized in providing ERS in the BES.			

Requested information
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
Augment the "Applicability – Facilities" and "Applicability-Functional Entities" sections in PRC-024 reliability standard to address (non-generation) transmission-connected dynamic reactive resources – both rotating machine (i.e. synchronous condenser) and power-electronics (e.g. Flexible AC Transmission System (FACTS) based. Also modify Requirements (including applicable attachments) as needed to ensure they continue to address the additional Facilities. As needed, also define new Glossary Terms for all or some of the transmission-connected dynamic reactive devices noted in the SAMS white-paper "*Transmission Connected Dynamic Reactive Resources – Assessment of Applicability in Reliability Standards*".
Project Scope (Define the parameters of the proposed project):
Revise the "Applicability – Facilities" section, "Applicability – Functional Entities" section, and Requirements (including applicable attachments) as needed in PRC-024 reliability standard to comprehensively address all varieties of transmission-connected dynamic reactive resources that are utilized in providing ERS in the BES. The Project 2020-02 Standard Drafting Team will consider defining new terms (Glossary of Terms) and determine if revisions to PRC-024 are needed. In addition, they will coordinate revisions to other standards with the appropriate drafting teams MOD-026/027 (Project 2020-06) and PRC-019/MOD-025 (Project 2021-01).
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1]which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):
The "Applicability – Facilities" and "Applicability-Functional Entities" sections in PRC-024 reliability standard will be revised to address (non-generation) transmission-connected dynamic reactive resources based on the recommendations summarized in Table 1 of the SAMS white-paper "*Transmission Connected Dynamic Reactive Resources – Assessment of Applicability in Reliability Standards*". The white-paper also provides the technical justifications for the recommended revisions and the associated reliability benefits. Also modify Requirements (including applicable attachments) as needed to ensure they continue to address the additional Facilities. As needed, also define new Glossary Terms for all or some of the transmission-connected dynamic reactive devices noted as items 1.a – 1.j in the Additional Considerations section of the SAMS white-paper.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Unknown

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
Synchronous condensers, HVDC Links (LCC or VSC), and power-electronics based transmission-connected reactive resources – also known as FACTS devices, such as Static Var Compensator (SVC), Static Synchronous Compensator (STATCOM).
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Transmission Owners in addition to the existing Functional Entities
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
"*Transmission Connected Dynamic Reactive Resources – Assessment of Applicability in Reliability Standards*" white-paper approved by SAMS members.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
PRC-019 SAR requested by SPCS and PRC-024 SAR requested by IRPTF The Project 2020-02 Standard Drafting Team will consider defining new terms (Glossary of Terms) and determine if revisions to PRC-024 are needed. In addition, they will coordinate revisions to other standards with the appropriate drafting teams MOD-026/027 (Project 2020-06) and PRC-019/MOD-025 (Project 2021-01).
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
No viable alternatives were found by SAMS.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following [Market Interface Principles]?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g. NPCC	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
☒ Draft SAR reviewed by NERC Staff ☒ Draft SAR presented to SC for acceptance ☒ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking

1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Revision of relevant Reliability Standards to include applicability of transmission-connected dynamic reactive resources ~~Revise the Applicable Facilities of MOD-025, MOD-026, MOD-027, PRC-019 and PRC-024 Standards to comprehensively include all types of dynamic reactive resources (including static var systems and FACTS) and DC transmission systems used to provide essential reliability services in the Bulk Electric System.~~		
Date Submitted:	February 24, 2020 (Revised on February 3, 2022)		
SAR Requester			
Name:	Hari Singh – Chair, System Analysis & Modeling Subcommittee (SAMS) (Revised by Project 2020-02 SAR DT)		
Organization:	Xcel Energy		
Telephone:	303-571-7095	Email:	hari.singh@xcelenergy.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
Dynamic reactive resources used to provide essential reliability services (ERS) in the BES include generation resources (rotating machine and inverter-based) as well as transmission connected dynamic reactive resources (power-electronics based). Existing reliability standards for verifying the capability, modeling and performance of dynamic reactive resources are only applicable to Facilities comprising generation resources. Augmenting the applicability of these standards to include (non-generation) transmission-connected reactive resources – both rotating machine (i.e. synchronous condenser) and			

Requested information
power-electronics based – will enhance the BES reliability by ensuring that the capability, models and performance is verified and validated for all varieties of dynamic reactive resources utilized in providing ERS in the BES.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
Augment the "Applicability – Facilities" and "Applicability-Functional Entities" sections in ~~MOD-025, MOD-026, MOD-027, PRC-019 and~~ PRC-024 reliability standard~~s~~ to address (non-generation) transmission-connected dynamic reactive resources – both rotating machine (i.e. synchronous condenser) and power-electronics (e.g. Flexible AC Transmission System (FACTS) based. Also modify Requirements (including applicable attachments) as needed to ensure they continue to address the additional Facilities. As needed, also define new Glossary Terms for all or some of the transmission-connected dynamic reactive devices noted in the SAMS white-paper "*Transmission Connected Dynamic Reactive Resources – Assessment of Applicability in Reliability Standards*".
Project Scope (Define the parameters of the proposed project):
Revise the "Applicability – Facilities" section, "Applicability – Functional Entities" section, and Requirements (including applicable attachments) as needed in ~~MOD-025, MOD-026, MOD-027, PRC-019 and~~ PRC-024 reliability standard~~s~~ to comprehensively address all varieties of transmission-connected dynamic reactive resources that are utilized in providing ERS in the BES. The Project 2020-02 Standard Drafting Team will consider defining new terms (Glossary of Terms) and determine if revisions to PRC-024 are needed. In addition, they will coordinate revisions to other standards with the appropriate drafting teams MOD-026/027 (Project 2020-06) and PRC-019/MOD-025 (Project 2021-01).
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):
The "Applicability – Facilities" and "Applicability-Functional Entities" sections in ~~MOD-025, MOD-026, MOD-027, PRC-019 and~~ PRC-024 reliability standard~~s~~ will be revised to address (non-generation) transmission-connected dynamic reactive resources based on the recommendations summarized in Table 1 of the SAMS white-paper "*Transmission Connected Dynamic Reactive Resources – Assessment of Applicability in Reliability Standards*". The white-paper also provides the technical justifications for the recommended revisions and the associated reliability benefits. Also modify Requirements (including applicable attachments) as needed to ensure they continue to address the additional Facilities. As needed, also define new Glossary Terms for all or some of the transmission-connected dynamic reactive devices noted as items 1.a – 1.j in the Additional Considerations section of the SAMS white-paper.

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Unknown
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
Synchronous condensers, HVDC Links (LCC or VSC), and power-electronics based transmission-connected reactive resources – also known as FACTS devices, such as Static Var Compensator (SVC), Static Synchronous Compensator (STATCOM).
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Transmission Owners in addition to the existing Functional Entities
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
"*Transmission Connected Dynamic Reactive Resources – Assessment of Applicability in Reliability Standards*" white-paper approved by SAMS members.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
PRC-019 SAR requested by SPCS and PRC-024 SAR requested by IRPTF The Project 2020-02 Standard Drafting Team will consider defining new terms (Glossary of Terms) and determine if revisions to PRC-024 are needed. In addition, they will coordinate revisions to other standards with the appropriate drafting teams MOD-026/027 (Project 2020-06) and PRC-019/MOD-025 (Project 2021-01).
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
No viable alternatives were found by SAMS.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following [Market Interface Principles](#)?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g. NPCC	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

Unofficial Nomination Form

Project 2020-02 Transmission-connected Dynamic Reactive Resources Generator Ride-through Standard (PRC-024-3 Replacement) Standard Drafting Team

Commented [A1]: The one-pager submitted to the SC states the nominations are for standard drafting team (not SAR DT) members. Please confirm which is correct.

Do not use this form for submitting nominations. Use the electronic form to submit nominations for standard drafting team (SDT) members by **8 p.m. Eastern, Thursday, July 14, 2022.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Josh Blume (via email), or at 470-755-0346.

Background

The Standard Authorization Request (SAR) presented to the Standards Committee May 18, 2022 is meant to retire PRC-024-3 and replace it with a performance-based ride-through standard that ensures generators remain connected to the BPS during system disturbances. Specifically, the SAR focuses on the generator protection and control systems that can result in the reduction or disconnection of generating resources during these events. The SAR also ensures protection or controls that fail to ride through system events are analyzed, addressed with a corrective action plan (if possible), and reported to necessary entities for situational awareness. From a risk-based perspective, the goal of the standard is to mitigate the ongoing and systemic performance issues identified across multiple Interconnections and across many disturbances analyzed by NERC and the Regions. These issues have been identified in inverter-based resources as well as synchronous generators, with many causes of tripping entirely unrelated to voltage and frequency protection settings as dictated by the currently effective version of PRC-024.

Standard affected: PRC-024-3

Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

SDT activities include participation in technical conferences, stakeholder communications and outreach events, periodic drafting team meetings and conference calls. Approximately one face-to-face meeting per quarter can be expected (on average three full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the drafting team sets forth. NERC is seeking individuals who possess experience with PRC-024 implmentation and protective relay setting background or Generator Operator and Transmission Owner (owning dynamic reactive resources) experience.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings (held at the Atlanta, GA NERC offices) and conference calls.

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RELIABILITY CORPORATION

Name:	
Organization:	
Address:	
Telephone:	
Email:	
Please briefly describe your experience and qualifications to serve on the requested SAR Drafting Team (Bio):	
If you are currently a member of any NERC drafting team, please list each team here: ☐ Not currently on any active SAR or standard drafting team. ☐ Currently a member of the following SAR or standard drafting team(s):	
If you previously worked on any NERC drafting team please identify the team(s): ☐ No prior NERC SAR or standard drafting team. ☐ Prior experience on the following team(s):	

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:		
☐ MRO ☐ NPCC ☐ RF	☐ SERC ☐ Texas RE ☐ WECC	☐ NA – Not Applicable

Select each Industry Segment that you represent:	
☐	1 — Transmission Owners
☐	2 — RTOs, ISOs
☐	3 — Load-serving Entities
☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	6 — Electricity Brokers, Aggregators, and Marketers
☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users
☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:	
☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		Email:	
Name:		Telephone:	
Organization:		Email:	

Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

Standards Announcement

Project 2020-02 Transmission-connected Dynamic Reactive Resources Generator Ride-through Standard (PRC-024-3 Replacement)

Drafting Team Nomination Period Open through July 14, 2022

Now Available

Nominations are being sought for standard drafting team members through **8 p.m. Eastern, July 14, 2022**.

Use the electronic form to submit a nomination. Contact Wendy Muller regarding issues using the electronic form. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Standard drafting team activities include participation in technical conferences, stakeholder communications and outreach events, periodic drafting team meetings and conference calls. Approximately one face-to-face meeting per quarter can be expected (on average three full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the drafting team sets forth. NERC is seeking individuals who possess experience with PRC-024 implementation and protective relay setting background or Generator Operator and Transmission Owner (owning dynamic reactive resources) experience.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings (held at the Atlanta, GA NERC offices) and conference calls.

Next Steps

The Standards Committee is expected to appoint members to the drafting team in August 2022. Nominees will be notified shortly after they have been appointed.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Josh Blume (via email) or at 404-446-2593. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-02 Transmission-connected Dynamic Reactive Resources observer list” in the Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Generator Ride-Through Standard (PRC-024-3 Replacement)		
Date Submitted:	April 28, 2022		
SAR Requester			
Name:	Mark Lauby, Senior Vice President and Chief Engineer, NERC Howard Gugel, Vice President, NERC John Moura, Director, NERC Ryan Quint, Senior Manager, NERC Rich Bauer, Principal, NERC Matt Lewis, Manager, NERC		
Organization:	North American Electric Reliability Corporation		
Telephone:	Mark Lauby – 404-446-9723	Email:	mark.lauby@nerc.net
SAR Type (Check as many as apply)			
☒ New Standard ☐ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term *(as needed)* ☒ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The ERO Enterprise has analyzed over 10 disturbances involving widespread loss of solar photovoltaic (PV) resources and has published multiple disturbance reports highlighting key findings and recommendations from these analyses. Across all events, a widespread loss of generating resources – solar PV, wind, synchronous generation, and battery energy storage systems (BESS) – have abnormally tripped, ceased current injection, or reduced power output with control interactions. Generator ride-through is a foundational essential reliability service. BPS-connected generating resources remaining connected during normal and contingency conditions is a critical component of BPS reliability. Ensuring fault ride-through capability enables dynamic reactive power support, frequency response, and other			

Requested information
services. The unexpected loss of widespread generating assets poses a significant risk to BPS reliability. The existing PRC-024-3 is an equipment settings standard focused solely on voltage and frequency protection. However, this standard is serving little to no value for ensuring BPS-connected inverter-based resources remain connected and supporting the BPS during grid disturbances. Furthermore, NERC has experienced multiple asset owners during the event analyses who have misconstrued PRC-024-3, resulting in incorrect or unnecessary protections applied to generating assets that have resulted in spurious and abnormal tripping events. The systemic tripping and reductions of inverter-based resources, in addition to notable concurrent tripping or performance from synchronous generating resources poses a risk to BPS reliability that must be addressed in a timely manner. This proposed standards project will address this known reliability risk with a more suitable performance-based standard that ensures generating resource ride-through performance for expected or planned BPS disturbances rather than focusing solely on a small subset of protections and controls that can trip generating resources.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The purpose of this SAR is to retire PRC-024-3 and replace it with a performance-based ride-through standard that ensures generators remain connected to the BPS during system disturbances. Specifically, this SAR focuses on the generator protection and control systems that can result in the reduction or disconnection of generating resources during these events. The SAR also ensures protection or controls that fail to ride through system events are analyzed, addressed with a corrective action plan (if possible), and reported to necessary entities for situational awareness. From a risk-based perspective, the goal of the standard is to mitigate the ongoing and systemic performance issues identified across multiple Interconnections and across many disturbances analyzed by NERC and the Regions. These issues have been identified in inverter-based resources as well as synchronous generators, with many causes of tripping entirely unrelated to voltage and frequency protection settings as dictated by the currently effective version of PRC-024.
Project Scope (Define the parameters of the proposed project):
The scope of this project includes the following: • Retire PRC-024-3, and create a new PRC standard or completely overhaul and replace the existing PRC-024 standard. • Creates a comprehensive, performance-based ride-through standard with the purpose of ensuring BES generating resources remain connected and providing essential reliability services during grid disturbances. • The scope of protections and controls involved in this ride-through standard shall include all generator protections and controls that affect the electrical output of the BES generating resource or plant. To be clear, the project should specify the protections and controls in scope of the ride-through performance and define the term ride-through, as necessary. This should, at a minimum, include all generator (synchronous or inverter-based) protections and controls at the individual

Requested information
generators, at the inverters, or within the plant (i.e., plant-level controls and protections or collector system protections). • The scope of the ride-through standard shall explicitly exclude auxiliary systems and their protection systems. Abnormal performance or unexpected tripping of these protections do not pose a systemic BES reliability risk. However, protections and controls directly focused on the generator and its prime mover (e.g., overspeed, power-load imbalance, overvoltage, phase jump, overcurrent) or plant-level (e.g., voltage, current, frequency, phase, etc.) have posed notable risks to BES reliability and should be addressed directly in this standard. • The new standard shall ensure that all unexpected or abnormal tripping or reductions in power output are reported by the GO to the TOP, BA, and RC.
-Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The following describe the proposed deliverable for this project: • The proposed deliverable is a new NERC standard (or significant overhaul and revision of PRC-024-3) that includes the following key elements: ▪ A performance-based approach to generator ride-through rather than an equipment settings standard. The new standard shall include requirements that BES resources shall ride through grid disturbances and include quantitative measures (see below) on expectations for ride-through that address all possible causes of tripping and power reductions from BES generating resources (particularly generator, turbine, inverter, and all plant-level protection and controls). ▪ A reporting requirement that all trips or reductions in power output are reported by the GO to the TOP, BA, and RC. ▪ A requirement that abnormal reductions in active power (i.e., tripping from protections or notable reductions from controls) are analyzed by the GO to develop a corrective action plan, if possible. Situations where corrective action plans are not able to be developed shall be reported to the TOP, BA, and RC. ▪ A clear requirement that momentary cessation, or temporary ceasing of current injection during BPS fault events, is deemed unacceptable performance for BES generating resources. Inverter-based generating resources employing momentary cessation shall develop a corrective action to mitigate its use. Legacy facilities prior to the effective date of the standard should receive an exemption; however, resources with a commercial operation date after the effective date of the standard (and possibly the PRC-024-3 implementation date) shall be

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information

required to eliminate the use of momentary cessation within "ride through envelopes" (e.g., the existing PRC-024 "No Trip Zone").

- The terms ride-through, trip, momentary cessation, and any other relevant terms should be defined in the NERC Glossary of Terms, if deemed necessary.
- A clear requirement that prolonged plant controller interactions that impede the ability of the resource to dynamically respond to the grid disturbance and preclude the ability to fully provide essential reliability services are deemed unacceptable and should be addressed by a corrective action plan.
- A requirement that if the TOP, BA, or RC inform the GO of a tripping occurrence, cessation event, or plant controller interactions that are not reported by the GO, then the GO shall be responsible for analyzing the facility's performance during the event, developing a corrective action plan, and reporting this to the TOP, BA, and RC.

The technical justification regarding the reliability-related need and benefits of this project are described in extensive detail in multiple NERC disturbance reports. All widespread solar PV loss events analyzed by the ERO Enterprise have involved extensive tripping and causes of reduction that are largely not address by PRC-024-3, many of which are unrelated to voltage and frequency tripping entirely. Furthermore, these multiple events have also involved the loss of synchronous generators for various reasons that should be considered in the development activities of this proposed project. Key disturbance reports include:

- NERC 2021 California Disturbances Report (2022)
- NERC Odessa Disturbance Report (2021)
- NERC San Fernando Disturbance Report (2020)
- NERC Palmdale Roost and Angeles Forest Disturbances Report (2019)
- NERC Canyon 2 Fire Disturbance Report (2018)
- NERC Blue Cut Fire Disturbance Report (2017)

NERC Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources (2019), developed by the NERC Inverter-Based Resource Performance Working Group (IRPWG) and endorsed by the NERC Planning Committee, specifically recommends that all Transmission Owners (TOs) per FAC-001 establish or improve interconnection requirements by including quantitative requirements related to ride-through performance. Below is an excerpt from this guideline:

Quantitative requirements ensure that resources behave in a manner that supports BPS reliability and also assists the GOs and inverter manufacturers in specifying equipment to meet these requirements. These requirements may involve a performance envelope (FRT capability) that must be met by the resource, typically derived based on interconnection studies, grid codes, Reliability Standards, and other factors deemed necessary by the TO. Having these requirements ensures that the resources, particularly inverter-

Requested information
based resources, are unlikely to operate in a mode that has not been previously studied. Examples of these quantitative performance requirements include, but are not limited to, the following: • *Pre- and post-fault short-circuit strength (equivalent impedance or short-circuit ratio (SCR)-based metric)) for worst case contingency conditions* • *RMS low voltage ride-through and high voltage ride-through* • *Instantaneous transient overvoltage* • *Instantaneous change in phase angle* • *Low frequency ride-through and high frequency ride-through* • *No use of momentary cessation, by exception only* These deliverables developed by the ERO Enterprise and its stakeholder groups serve as a strong technical basis for ensuring resources successfully ride through grid disturbances and support the BPS by providing essential reliability services moving forward.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Incremental costs are expected for GOs that currently do not analyze the performance of their generating assets following grid disturbances, which has been shown during the NERC disturbance analyses to be a systemic reliability issue for solar PV resources in particular. GOs will need to assess their ride-through capabilities more comprehensively than in the past, which may have some associated costs. Minimal costs are associated with reporting of tripping occurrences. Facilities with abnormal or unexpected trips that can be mitigated with corrective actions will have some incremental costs; however, these improvements will help ensure adequate levels of reliability of the BES. Otherwise, cost impacts for this project are expected to be minimal.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
BES generating resources.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Generator Owners, Generator Operators, Reliability Coordinators, Transmission Operators, Transmission Owners, Transmission Planners, Planning Coordinators
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Requested information
This SAR is an outcome of ongoing analyses conducted by the ERO Enterprise regarding widespread inverter-based resource tripping events. Furthermore, the NERC IRPWG has developed comprehensive recommendations for improved performance of inverter-based resources, including the recommendation to develop comprehensive ride-through requirements.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
No.
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
NERC has evaluated industry progress toward adopting the recommendations outlined in NERC guidelines, white papers, its prior Alerts, and other industry efforts. NERC believes that a nationwide standard for consistent requirements for generating resource ride-through is necessary to immediately address generating resource ride-through during grid disturbances moving forward.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes

Market Interface Principles	
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	None

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Unofficial Comment Form

Project 2020-02 Transmission-connected Dynamic Reactive Resources Generator Ride-through Standard (PRC-024-3 Replacement) Standard Authorization Request

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on the **Generator Ride-through Standard (PRC-024-3 Replacement) Standard Authorization Request (SAR).** Comments must be submitted by **8 p.m. Eastern, Thursday, July 14, 2022.**

Additional information is available on the project page. If you have questions, contact Standards Developer, Josh Blume (via email), or at 470-755-0346.

Background Information

The Standard Authorization Request (SAR) presented to the Standards Committee May 18, 2022 is meant to retire PRC-024-3 and replace it with a performance-based ride-through standard that ensures generators remain connected to the BPS during system disturbances. Specifically, the SAR focuses on the generator protection and control systems that can result in the reduction or disconnection of generating resources during these events. The SAR also ensures protection or controls that fail to ride through system events are analyzed, addressed with a corrective action plan (if possible), and reported to necessary entities for situational awareness. From a risk-based perspective, the goal of the standard is to mitigate the ongoing and systemic performance issues identified across multiple Interconnections and across many disturbances analyzed by NERC and the Regions. These issues have been identified in inverter-based resources as well as synchronous generators, with many causes of tripping entirely unrelated to voltage and frequency protection settings as dictated by the currently effective version of PRC-024.

Standard affected: PRC-024-3

Questions

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

   ☐ Yes
   ☐ No

   Comments:

2. Provide any additional comments for the standard drafting team to consider, if desired.

   Comments:

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2020-02 Transmission-connected Dynamic Reactive Resources Generator Ride-through Standard (PRC-024-3 Replacement) | Standard Authorization Request

Formal Comment Period Open through July 14, 2022

Now Available

A 45-day formal comment period for the **Generator Ride-through Standard (PRC-024-3 Replacement) Standard Authorization Request** is open through **8 p.m. Eastern, Thursday, July 14, 2022**.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The drafting team will review all responses received during the comment period and determine the next steps of the project.

For more information or assistance, contact Standards Developer, Josh Blume (via email) or at 404-446-2593. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-02 Transmission-connected Dynamic Reactive Resources observer list” in the Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2020-02 Transmission-connected Dynamic Reactive Resources | Generator Ride-through (PRC-024-3 Replacement) | Standard Authorization Request
Comment Period Start Date:	5/31/2022
Comment Period End Date:	7/14/2022
Associated Ballots:	

There were 40 sets of responses, including comments from approximately 103 different people from approximately 72 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope, please provide your recommendation and explanation.

2. Provide any additional comments for the drafting team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
DTE Energy - Detroit Edison Company	Adrian Raducea	3,5		DTE Energy - DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison	5	RF
					patricia ireland	DTE Energy	4	RF
WEC Energy Group, Inc.	Christine Kane	3,4,5,6		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
Tacoma Public Utilities (Tacoma, WA)	Jennie Wike	1,3,4,5,6	WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					Marc Donaldson	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF

Florida Municipal Power Agency	LaKenya VanNorman	3,4,5,6	SERC	Florida Municipal Power Agency (FMPA)	Chris Gowder	Florida Municipal Power Agency	5	SERC
					Dan O'Hagan	Florida Municipal Power Agency	4	SERC
					Carl Turner	Florida Municipal Power Agency	3	SERC
					Jade Bulitta	Florida Municipal Power Agency	6	SERC
FirstEnergy - FirstEnergy Corporation	Mark Garza	1,3,4,5,6		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Tricia Bynum	FirstEnergy - FirstEnergy Corporation	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Pacific Gas and Electric Company	Michael Johnson	1,3,5	WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC
					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					James Mearns	Pacific Gas and Electric Company	5	WECC
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama	3	SERC

						Power Company		
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Jim Howell	Southern Company - Southern Company Services, Inc. - Gen	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC		NPCC Regional Standards Committee	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Harish Vijay Kumar	IESO	2	NPCC
					David Kiguel	Independent	7	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC

Shivaz Chopra	New York Power Authority	5	NPCC
Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
Nurul Abser	NB Power Corporation	1	NPCC
Randy MacDonald	NB Power Corporation	2	NPCC
Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
Vijay Puran	NYSPS	6	NPCC
ALAN ADAMSON	New York State Reliability Council	10	NPCC
Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
Brian Robinson	Utility Services	5	NPCC
Quintin Lee	Eversource Energy	1	NPCC
John Pearson	ISONE	2	NPCC
Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
Chantal Mazza	Hydro-Quebec	2	NPCC

					Michele Tondalo	United Illuminating Co.	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope, please provide your recommendation and explanation.	
Brian Lindsey - Entergy - 1,3,6	
Answer	No
Document Name	
Comment	
Should add new R5 to PRC-024-3: "Generator Owners shall analyze and have a corrective action plan (if possible), and report to necessary entities any failure to ride through a system event."	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
The proposed standard should cover “tripping” and not include “reductions”, as the specified level can be subjective.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	No
Document Name	
Comment	
Constellation does not agree with the proposed scope as the scope is far reaching into multiple standards not just PRC-024-3 and the impact to those standards is not clearly defined. Kimberly Turco on behalf of Constellation Segements 5 and 6	

Likes 0	
Dislikes 0	
Response	
Alison Mackellar - Constellation - 5,6	
Answer	No
Document Name	
Comment	

Constellation does not agree with the proposed scope as the scope is far reaching into multiple standards not just PRC-024-3 and the impact to those standards is not clearly defined.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5,6	
Answer	No
Document Name	
Comment	

AEP agrees with the concerns related to IBRs and the performance issues that have been previously noted but we do not agree that PRC-024 should be revised or replaced with ride-through obligations added for synchronous generation. AEP recommends that PRC-024 be retained as it currently is, and recommends creation of a new standard containing ride-through obligations for IBRs only. AEP does not see a reliability justification for developing ride-through obligations for synchronous generation and advises against any efforts to do so since, as also noted by EEI, such units have been seen to perform well in the various cited events.

The following comments are offered in the event that the SDT develops obligations for both synchronous generation and IBRs (contrary to our recommendation above).

The fourth bullet of the SAR's Project Scope states "protections and controls directly focused on the generator and its prime mover (e.g., overspeed, power-load imbalance, overvoltage, phase jump, overcurrent) or plant-level (e.g., voltage, current, frequency, phase, etc.) have posed notable risks to BES reliability." AEP does not agree with the proposed inclusion of overspeed and power-load imbalance, as both must be present to protect against equipment damage. Even if their presence could at times pose a reliability risk to the system, these protective functions need to be retained for the unit's own protection and continuing availability. AEP recommends removing overspeed and power-load imbalance from the SAR.

Requirement R3 in the current version of PRC-024 requires the Generator Owner to "document each known regulatory or equipment limitation that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1

or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice." Care should be taken to retain this provision in any new or revised standard.	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
The scope states generator overcurrent and plant-level current should be addressed in this standard. Overcurrent is addressed by PRC-025. It does not seem right to also include current in this standard. Other than the inclusion of overcurrent, the scope seems reasonable.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO	
Answer	No
Document Name	
Comment	

The MRO NSRF in general agrees with both the concept and scope of this SAR. However, the MRO NSRF is voting no due to the following concerns:

1. *A reporting requirement that all trips or reductions in power output are reported by the GO to the TOP, BA, and RC.*

The MRO NSRF disagrees with this deliverable. The Reliability Coordinator (RC), Balancing Authority (BA) and Transmission Operator (TOP) should be responsible for determining the magnitude threshold and duration-of-time threshold for the Generator Owner (GO)/ Generator Operator (GOP) to report trips or reductions in power output. This will ensure that the RC, BA & TOP are not burdened by notifications for trips/reductions that do not affect the Bulk Electrical System (BES) and ultimately take the RC's, BA's & TOP's attention away from matters of higher priority for ensuring the reliability of the BES. In addition, it is the NSRF belief that the RC, BA & TOP currently has the ability request information about trips or reductions in power output from the GO/GOP under the regulatory framework of NERC Reliability Standard IRO-010-4 Reliability Coordinator Data Specification and Collection & NERC Reliability Standard TOP-003-4 - Operational Reliability Data.

Further, reductions in power will occur for a wide variety of reasons such as clouds passing over or the setting of the sun at a solar generation facility, a drop in wind speed at a wind generation facility, wet coal, changes in condenser circulating water temperature or discharge water temperature limits at a thermal plant, starting an additional large fan or pump, inlet air temperature changes to gas turbines, reduced water flow at a hydro plant – none of these causes of power reduction would have any relation to PRC requirements and no additional reporting other than that required by existing NERC

Standard IRO-010 & TOP-003 requirements should be necessary. The MRO NSRF believes this deliverable should say “A reporting requirement that all trips or reductions in power output in response to grid disturbances are reported by the GO as required by the applicable TOP, BA, and RC.”

2. *A requirement that abnormal reductions in active power (i.e., tripping from protections or notable reductions from controls) are analyzed by the GO to develop a corrective action plan, if possible. Situations where corrective action plans are not able to be developed shall be reported to the TOP, BA, and RC.*

The MRO NSRF disagrees with this deliverable. The MRO NSRF believes that the ‘trip’ portion of this deliverable is already an enforceable requirement under the regulatory framework of NERC Reliability Standard PRC-004-6 - Protection System Misoperation Identification and Correction.

As written, ‘*notable reductions from controls*’, lacks the detail required to provide a standard drafting team (SDT) with proper direction to develop a requirement(s). As this Standard Authorization Request (SAR) relates to dynamic ride-through performance of generators the MRO NSRF would request that the SAR SDT add an example magnitude threshold and duration-of-time threshold for ‘notable reductions from controls’. Adding the additional information will prevent any developed requirement(s) from overreaching beyond the intention of this SAR.

3. *A clear requirement that momentary cessation, or temporary ceasing of current injection during BPS fault events, is deemed unacceptable performance for BES generating resources. Inverter-based generating resources employing momentary cessation shall develop a corrective action to mitigate its use. Legacy facilities prior to the effective date of the standard should receive an exemption; however, resources with a commercial operation date after the effective date of the standard (and possibly the PRC-024-3 implementation date) shall be required to eliminate the use of momentary cessation within “ride through envelopes” (e.g., the existing PRC-024 “No Trip Zone”).*

The implementation date for NERC Reliability Standard PRC-024-3 — Frequency and Voltage Protection Settings for Generating Resources (NERC PRC-024-3) is October 01, 2022. As stated by the SAR requestors:

• “The existing PRC-024-3 is an equipment settings standard focused solely on voltage and frequency protection. However, this standard is serving little to no value for ensuring BPS-connected inverter-based resources remain connected and supporting the BPS during grid disturbances.”

• “The purpose of this SAR is to retire PRC-024-3 and replace it with a performance-based ride-through standard that ensures generators remain connected to the BPS during system disturbances.”

• “Retire PRC-024-3, and create a new PRC standard or completely overhaul and replace the existing PRC-024 standard.”

Based on these statements the MRO NSRF believes all generators with a commercial operation date prior to the effective date of requirements to be developed based on this SAR should not have to comply or retrofit. It is clear that any requirements developed based on this SAR will be different from the requirements of NERC PRC-024-3 and therefore the generators that need to comply should be adjusted accordingly.

4. The performance-based standard should include documented equipment limitation exemptions similar to NERC PRC-024-3 R3 and these should apply to all generator types rather than just carving out an exemption for the application of momentary cessation on legacy inverter-based resources (IBR) existing prior to the effective date of the standard (and possible the PRC-024-3 implementation date).   For example, if an existing turbine has frequency limitations that do not meet the requirements of the new ride-through standard, no corrective action plan should be necessary should the turbine trip in response to a frequency excursion outside of its capability. There appears to be nothing in the SAR that addresses limitations of existing equipment other than that of legacy IBRs applying momentary cessation.

5. The MRO NSRF believes that there is little justification for retiring NERC PRC-024-3 for synchronous generators and that any new standard should be focused on IBR performance issues. If the scope is to “create a comprehensive, performance-based ride-through standard with the purpose of ensuring BES generating resources remain connected and providing essential reliability services during grid disturbances”, why would only PRC-024-3 be considered for retirement rather than to include the retirement of other relay setting standards such as PRC-025-2, which has the purpose to assure that load responsive relays are set to prevent unnecessary tripping during system disturbances, and/or the elimination of GO applicability in PRC-026-1, which has the purpose to ensure that load-responsive relays are expected to not trip in response to stable power swings during non-Fault conditions? The MRO NSRF believes that if a truly comprehensive performance-based ride-through standard is created, then the regulatory burden of other relay setting standards pertaining to how generator protection responds to grid disturbances should be eliminated by retiring PRC-025-2 and eliminating the applicability of PRC-026-1 to Generator Owners. It seems that a comprehensive generator ride-through standard would apply to not only

24, 27, and 59 functions (PRC-024-3) but would also include trips of generating resources in response to 21, 50, 51, 51VR, 51VC, 67 (PRC-025-2) and/or 21, 40, ,50, 51, 78 (PRC-026-1) function operations in response to grid disturbances.

Further, and accounting for the aforementioned comments, the MRO NSRF recommends the drafting team consider whether retiring PRC-024-3 and replacing it with a performance-based ride-through standard may change, for example, the Generator no trip zones settings. This action would potentially affect PRC-006, and the SAR should open its scope to contemplate potential changes to that standard, and any other affected standard, if needed. This comment is to ensure the drafting team crafts a SAR with the necessary scoping parameters to make changes to associated standards as needed.

6. *A clear requirement that prolonged plant controller interactions that impede the ability of the resource to dynamically respond to the grid disturbance and preclude the ability to fully provide essential reliability services are deemed unacceptable and should be addressed by a corrective action plan.*

This requirement seems to be focused on eliminating some of the undesirable IBR performance issues, but the wording of this deliverable could be interpreted to apply to integrated plant or unit protection schemes that may indeed "impede the ability of the resource to dynamically respond to grid disturbances" but are designed to protect the boiler or nuclear reactor from pressure or level excursions, steam turbines from overspeed, operation at resonant frequencies or moisture intrusion, etc. GOs should be able to protect their equipment from catastrophic damage without having to implement a corrective action plan should these protection or control features impede dynamic response to grid disturbances.

Likes 1	Southern Indiana Gas and Electric Co., 3,5,6, Todd Anna
Dislikes 0	

Response

Israel Perez - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

We do not agree with the proposed scope described in the SAR, as more clarification of expectations and deliverables are needed. The proposed scope is not clear if the changes would require the installation of additional protection devices to our generators or switchyards and if additional DCS/computer points need to be monitored. Would the changes require third-party generator studies and at what frequency? We are concerned that these changes, which are still unclear, will require additional preventative tasks and specialized personnel necessary to perform these tasks. If the disturbance in the grid is large enough, wouldn't it be better for our generators to disconnect and/or trip to prevent equipment damage? A unit/generator restart would have a faster turnover and would be more efficient than having a damaged generator that motored because we couldn't disconnect it from the large disturbance of the grid.

In addition, it seems that we must wait until "performance" metrics are outlined and how metrics meet baseline criteria. The reference documents outline some of the criteria for measurement and submittal methods but not the full metric. The "ride through" criteria is mentioned, as a "no trip zone" in the attached document but not a clear definition of achieving that target. The process for defining the performance characteristics of a generation resources is not specified other than a system strength specification which we believe would require a separate criterion for each BES bus depending on the generation in the vicinity. It would be difficult to define and enforce and even more difficult to monitor.

The events in southern California revealed that generation went into a current cessation mode during a frequency/voltage excursion and PRC-024-3 covers this issue. The event would expand the scope from generation ride through to include any event where generation was reduced or removed from service for say auxiliary systems being removed from service. This subject might fall under PRC-004. If the tripping or reduction in generation is entirely unrelated to frequency or voltage, then we should have a separate standard that addresses this issue.

The deliverable noted is a requirement for reporting all trips and abnormal reductions in active power. In our experience most "abnormal" reductions are prime mover related. If it was intended to only require reporting an abnormal reduction or trip during a system disturbance only, it is not clear that this

deliverable is being met. We agree that generation outages due to frequency and voltage excursions should be tracked but the scope of the SAR goes well beyond that point. Why take a perfectly fine standard that addresses a known system issue and expand the scope into something that is not clearly defined. Consider expanding the scope of PRC-004 instead and include operations that affect the output of a BES Generation source and leave PRC-024-3 as a frequency and voltage ride through standard.	
Likes 0	
Dislikes 0	
Response	

Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Xcel Energy supports the comments offered by EEI, NAGF, and MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

Southern Company does not agree due to the following concerns:

1. *A reporting requirement that all trips or reductions in power output are reported by the GO to the TOP, BA, and RC.*

Southern Company disagrees with this deliverable. **The RC, BA, and TOP should be responsible parties for determining the magnitude threshold and duration-of-time thresholds GO/GOP to report trips or reductions in power output.** This will ensure that the RC, BA & TOP are not burdened by notifications for trips/reductions that do not affect the Bulk Electrical System (BES) and ultimately take their attention away from matters of higher priority for ensuring the reliability of the BES. In addition, it is the belief of Southern Company that **the RC, BA & TOP already has the ability request information about trips or reductions in power output from the GO/GOP under the regulatory framework of NERC Reliability Standard IRO-010-4 and TOP-003-4.**

2. *A requirement that abnormal reductions in active power (i.e., tripping from protections or notable reductions from controls) are analyzed by the GO to develop a corrective action plan, if possible. Situations where corrective action plans are not able to be developed shall be reported to the TOP, BA, and RC.*

Southern Company disagrees with this deliverable. **Southern Company believes that the ‘trip’ portion of this deliverable is already an enforceable requirement under the regulatory framework of NERC Reliability Standard PRC-004-6.**

As written, *‘notable reductions from controls’*, lacks the detail required to provide a standard drafting team (SDT) with proper direction to develop a requirement(s). **As this Standard Authorization Request (SAR) relates to dynamic ride-through performance of generators Southern Company requests that the SAR SDT add an example magnitude threshold and duration-of-time threshold for ‘notable reductions from controls’.** Adding the additional information will prevent any developed requirement(s) from overreaching beyond the intention of this SAR. The communication of unit derates, where necessary for system operation, is likely already being communicated where specified by the RC/BA/TOP data specifications of IRO-010 and TOP-003.

3. *A clear requirement that momentary cessation, or temporary ceasing of current injection during BPS fault events, is deemed unacceptable performance for BES generating resources.* Inverter-based generating resources employing momentary cessation shall develop a corrective action to mitigate its use. Legacy facilities prior to the effective date of the standard should receive an exemption; however, resources with a commercial operation date after the effective date of the standard (and possibly the PRC-024-3 implementation date) shall be required to eliminate the use of momentary cessation within “ride through envelopes” (e.g., the existing PRC-024 “No Trip Zone”).

The opening statement is contrary to real world expectations that the generation resource is not allowed to protect its equipment for BES system events. If this is the expectation, then the BES system should not be allowed to have fault events in the first place.

The implementation date for NERC Reliability Standard PRC-024-3 — Frequency and Voltage Protection Settings for Generating Resources (NERC PRC-024-3) is October 01, 2022. As stated by the SAR requestors:

• “The existing PRC-024-3 is an equipment settings standard focused solely on voltage and frequency protection. However, this standard is serving little to no value for ensuring BPS-connected inverter-based resources remain connected and supporting the BPS during grid disturbances.”

• “The purpose of this SAR is to retire PRC-024-3 and replace it with a performance-based ride-through standard that ensures generators remain connected to the BPS during system disturbances.”

• “Retire PRC-024-3, and create a new PRC standard or completely overhaul and replace the existing PRC-024 standard.”

Based on these statements Southern Company believes all generators with a commercial operation date prior to the effective date of requirements to be developed based on this SAR should not have to comply or retrofit. It is clear that any requirements developed based on this SAR will be different from the requirements of NERC PRC-024-3 and therefore the generators that need to comply should be adjusted accordingly.

4. The premise that there have been notable concurrent tripping or performance from synchronous generating resources due to frequency and voltage protection settings being too sensitive is flawed. There have not been increasing trends of synchronous machine protection system misoperations to justify that premise. The application of a ride through standard for synchronous machine generating plants was fully investigated during the original drafting effort of PRC-024 between 2008-2014. The conclusion of the standard drafting team, after multiple drafts, extended comment and consideration of comments from industry, direct consultation with FERC by standard drafting team members resulted in the realization that the standard could go no further than to specify a regions for restricting the tripping of those generators by protective relays for voltage-time and frequency-time areas that would cause the units to not be tripped for the majority of system events where the voltage or frequency was not normal. Further attempts to apply a ride through requirement should be abandoned for synchronous machines to avoid wasting everyone’s time by having to restate why it is not feasible for that generation type.

5. Further, there are limited modifications that can be made to the existing equipment to achieve the goal of 100% ride-thru ability to any grid disturbance. Simply passing a regulation specifying it must be done does not change the ability of the equipment to do so. The replacement of existing inverters is not feasible – the power ratings and voltage/current specifications of existing installed invertors do not match the inverters offered today. The collection system of a PV plant cannot be reconfigured economically once it is in place.

6. Any additional ride through requirements should only be applicable to equipment placed in service after changes are made to this standard which may require additional ride-thru capabilities for IBR plants. We suggest that the transmission interconnection agreements be the proper method to assure that newly connected IBR facilities are built to maximize their ride through capability.

7. The lack of a specific grid disturbance for which generating resources are to be required to ride-through is problematic. If specific disturbance characteristics are specified, the generating community might have a fighting chance to design systems to achieve the goals. The application of global “you must ride through all grid disturbance” requirements to existing equipment not designed to do so is ludicrous.

8. The SAR states that auxiliary systems and their protection systems are explicitly excluded. The sub-systems of a conventional synchronous machine generating station are essential for the normal plant operation. Without many of those sub-systems, the main generator cannot run. The sub-system may be essential to the mechanical operation of the turbine too. Any system disturbance that causes any of those sub-systems to not be available will immediately affect the turbine/generator ability to run. The controls of the generator and turbine are interlaced and interlinked with the sub-systems. They cannot be removed from affecting the entire unit operation. In effect, they cannot be separated from the generator and the unit availability. During system disturbances where sustained grid low voltage occurs, those sub-systems may or may not experience trouble. During the initial PRC-024 development, the Luminant company reported that some low voltage contactors dropped out for low voltage conditions, and others did not. In subsequent grid low voltage disturbances, it was observed that different sets of contactors dropped out. The indefinite response of magnetically sealed in contactor behavior for low voltage conditions was one of the problems with any meaningful successful application of ride-through standards to those types of facilities.

9. The SAR indicates that the desire of the standard revision is to address all possible causes of tripping and power reductions. Addressing ALL POSSIBLE CAUSES is indefinite and unachievable. No failsafe system can be built to withstand all possible causes.

10. With regard to the SAR question on alternatives, for which the SAR drafters included this text:

NERC has evaluated industry progress toward adopting the recommendations outlined in NERC guidelines, white papers, its prior Alerts, and other industry efforts. NERC believes that a nationwide standard for consistent requirements for generating resource ride-through is necessary to immediately address generating resource ride-through during grid disturbances moving forward.

Southern Company has implemented all possible inverter setting changes included in the two NERC alerts on the Loss of Solar Resources. We note that several of our units have continued to react to major grid disturbances by ceasing to generate. The communication of the adjustment of the settings, and the limitations to adjustments we have discerned, have been communicated to the parties included in the NERC alert recommendations. It is for this reason we implore the SDT to look forward rather than backward with change requirements. The electric grid is not in immediate imminent danger due to this current condition. The requirement of maximizing IBR equipment connectivity and grid disturbance resolution support is best addressed through the transmission interconnection requirements rather than through reliability standards.

Likes 0	
Dislikes 0	

Response

Anna Todd - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	No
Document Name	

Comment

Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) would like to thank the SAR Standards Drafting Team for the opportunity to provide feedback on Project 2020-02 “Transmission-connected Dynamic Reactive Resources Generator Ride-through Standard (PRC-024-3 Replacement).” SIGE does not agree with the proposed scope as described in the SAR and would request additional clarifications before agreeing to the proposed project.

Project 2020-02 describes a proposed deliverable of “A reporting requirement that all trips or reductions in power output are reported by the GO to the TOP, BA, and RC.” This phrasing should be specific to Protection Systems, as it is unclear at what point an entity is required to report. It should be defined whether reporting is required every time a unit trips due to any circumstance, or to which point reporting is required. For example, SIGE does not agree that reporting a trip due to weather should fall under the scope of this standard.

The use of phrasing within the existing PRC-024 standard, such as “No Trip Zone,” are beneficial because they are specific to Voltage and Frequency. These terms are needed to help regulate the standard.

SIGE does agree with the proposed deliverable of “a clear requirement that momentary cessation, or temporary ceasing of current injection during BPS fault events, is deemed unacceptable performance for BES generating resources.”

Likes 0	
Dislikes 0	

Response

Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments

Answer	No
Document Name	

Comment

PG&E agrees with the comments provided by EEI that there have been performance issues with Solar PV Inverter Based Resources (IBRs) that need to be addressed, but as indicated by EEI, PG&E does not agree the replacement of PRC-024-3 is required to address those issues.

The current PRC-024-2 Requirements have worked well for synchronous generators, and it is expected that PRC-024-3 will improve the performance of those generators in maintaining the reliable operation of the Bulk Electric System (BES). As noted by EEI, there were losses of synchronous generator in some of the six disturbances noted in the SAR, but none of those appeared to be unexpected, unusual, or a result of non-compliance with the current PRC-024 Standard.

PG&E personnel responsible for PRC-024 believe trying to add an entire set of additional Requirements for IBRs on top of the current PRC-024 Requirements, or changing the Standard to be performance based for all generators would be extremely complex to implement and maintain, and would not improve the reliability for synchronous generators. PG&E recommends IBR performance should be covered under a new Standard specifically developed for the unique characteristics of IBRs.

Likes 0	
Dislikes 0	

Response

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3

Answer	No
Document Name	

Comment

MidAmerican supports MRO NSRF and EEI comments.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Evergy - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #1.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

WEC Energy Group is voting no due to the following concerns:

- "Purpose or Goal" section calls for complete replacement of PRC-024-3 to ensure generators remain connected during disturbances, but the "Industry Need" section clearly identifies this issue applies to IBR only. Industry can agree that current standard as is, is very well effective for traditional synchronous generating resources, therefore WEC believes that standard does not need to be rewritten but rather modified to cover specific IBR issues. WEC believes that statement "… notable concurrent tripping or performance from synchronous generating resources…" is not well supported by data from recent disturbances.
- Proposed "performance based" term needs to be better defined within the SAR.
- If industry recommendation is to include other protective elements or control systems, then it should be done separately and new standards should be developed. Good examples are PRC-025 and PRC-026.
- Some of the "possible causes of tripping and power reductions" listed in SAR are load responsive in nature, therefore should be addressed within existing Standards that cover load-responsive requirements.
- "Detailed Description" section indicates that momentary cessation is deemed unacceptable. Did the SAR requester confirm with all equipment manufacturers that momentary cassation can completely be eliminated? There are still inverter manufacturers that produce equipment with momentary cessation in their design because of current limiting components. The SAR suggest a corrective action plan to be developed to mitigate the issue. What if issue cannot be mitigated?

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	

AZPS agrees with the following comments that were submitted by EEI on behalf of its members:

“The incidental operation of synchronous generators during some of the identified six NERC disturbance reports do not warrant the creation of a new ride through Reliability Standard replacing PRC-024-3 because the performance of most of the affected resources, outside of the solar PV resources, performed as designed and expected, and met the requirements of PRC-024-3.

While there were losses of synchronous generators in some of the six disturbance reports cited in the proposed SAR, none appear to be unexpected, unusual or the result of non-compliance with PRC-024”

“Additionally, if the intent of the SAR is to “create a comprehensive, performance-based ride-through standard,” development of a standard would need to account for retirement of other relay setting standards such as PRC-025-2 and PRC-026-1, to prevent duplicative requirements and compliance obligations.”

Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	

Minnesota Power supports EEI’s comments for this question.

Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	

In describing the scope, the SAR states *"The scope of the ride-through standard shall explicitly exclude auxiliary systems and their protection systems. Abnormal performance or unexpected tripping of these protections do not pose a systemic BES reliability risk. However, protections and controls directly focused on the generator and its prime mover (e.g., overspeed, power-load imbalance, overvoltage, phase jump, overcurrent) or plant-level (e.g., voltage, current, frequency, phase, etc.) have posed notable risks to BES reliability and should be addressed directly in this standard."* However, auxiliary systems that in turn unexpectedly trip an entire plant pose a risk to reliability. While these systems should not be explicitly modeled, the OP, BA and RC should be in a position to understand when a facility will trip. As an absolute minimum, this information should be required from facilities currently being planned and installed.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

The NAGF provides the following comments for consideration:

1. The NAGF believes that there is little justification for retiring PRC-024-3 for synchronous generators and that any new standard should be focused on IBR performance issues. Note that GOs have invested tremendous effort and money in achieving compliance with the PRC standards and are achieving the desired enhancement of BES reliability. Replacing them with something substantially different would require significant expenditures with no identifiable benefit. Any new standard should address only gaps in existing standards, as opposed to tearing down and rebuilding them.

2. Project Scope Comments:

a) Second Bullet: "Creates a comprehensive, performance-based ride-through standard with the purpose of ensuring BES generating resources remain connected and providing essential reliability services during grid disturbances."

The NAGF recommends that other relay-setting PRC standards be considered for retirement/modification beyond PRC-024-3. For example, PRC-025-2, which has the purpose to assure that load responsive relays are set to prevent unnecessary tripping during system disturbances, and PRC-026-1, which has the purpose to ensure that load-responsive relays are expected to not trip in response to stable power swings during non-Fault conditions. The NAGF believes that if a truly comprehensive performance-based ride-through standard is created, then the regulatory burden of other relay setting PRC standards pertaining to how generator protection responds to grid disturbances should be reviewed and incorporated. It seems that a comprehensive generator ride-through standard would apply to not only 24, 27, and 59 functions (PRC-024-3) but would also include trips of generating resources in response to 21, 50, 51, 51VR, 51VC, 67 (PRC-025-2) and/or 21, 40, ,50, 51, 78 (PRC-026-1) function operations in response to grid disturbances.

3. Detailed Description of Project Deliverables Comments:

a) Bullet #3: "A reporting requirement that all trips or reductions in power output are reported by the GO to the TOP, BA, and RC."

The NAGF believes that this statement is too vague or is stated imprecisely for this deliverable. Reductions in power will occur for a wide variety of reasons such as clouds passing over or the setting of the sun at a solar farm, a drop in wind speed, wet coal, changes in condenser circulating water temperature or discharge water temperature limits at a thermal plant, starting an additional large fan or pump, inlet air temperature changes to gas turbines, reduced water flow at a hydro plant – none of these causes of power reduction would have any relation to PRC requirements and no additional reporting other than that required by existing TOP requirements should be necessary. We believe this deliverable should be more focused, such as "A reporting requirement that all trips or reductions in power output in response to grid disturbances are reported by the GO to the TOP, BA, and RC."

b) Bullet #4: "A requirement that abnormal reductions in active power (i.e., tripping from protections or notable reductions from controls) are analyzed by the GO to develop a corrective action plan, if possible. Situations where corrective action plans are not able to be developed shall be reported to the TOP, BA, and RC."

The NAGF believes that such trip analysis and corrective actions are already addressed by PRC-004 and therefore this deliverable/requirement is redundant.

c) Bullet #5: "Legacy facilities prior to the effective date of the standard should receive an exemption; however, resources with a commercial operation date after the effective date of the standard (and possibly the PRC-024-3 implementation date) shall be required to eliminate the use of momentary cessation within "ride through envelopes" (e.g., the existing PRC-024 "No Trip Zone").

The NAGF supports the exemption for legacy IBR facilities. The NAGF recommends that the performance-based standard include documented equipment limitation exemptions similar to PRC-024-3 R3 and these should apply to all generator types rather than just carving out an exemption for the application of momentary cessation on legacy IBRs existing prior to the effective date of the standard (and possible the PRC-024-3 implementation date). For example, if an existing turbine has frequency limitations that do not meet the requirements of the new ride-through standard, no corrective action plan should be necessary should the turbine trip in response to a frequency excursion outside of its capability. There appears to be nothing in the SAR that addresses limitations of existing equipment other than that of legacy IBRs applying momentary cessation.

d) Bullet #7: "A clear requirement that prolonged plant controller interactions that impede the ability of the resource to dynamically respond to the grid disturbance and preclude the ability to fully provide essential reliability services are deemed unacceptable and should be addressed by a corrective action plan."

The NAGF is concerned with the potential ambiguity associated with this deliverable. This deliverable seems to be focused on eliminating some of the undesirable IBR performance issues, but the wording of this deliverable could be interpreted to apply to integrated plant or unit protection schemes that may indeed "impede the ability of the resource to dynamically respond to grid disturbances" but are designed to protect the boiler or nuclear reactor from pressure or level excursions, steam turbines from overspeed, operation at resonant frequencies or moisture intrusion, etc. Generator Owners should be able to protect their equipment from catastrophic damage without having to implement a corrective action plan should these protection or control features impede dynamic response to grid disturbances.

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2

Answer	No
Document Name	

Comment

On the bottom of page 2, the SAR states: "The scope of protections and controls involved in this ride-through standard shall include all generator protections and controls that affect the electrical output of the BES generating resource or plant. To be clear, the project should specify the protections and controls in scope of the ride-through performance and define the term ride-through, as necessary."

Will the scope include requirements that developers/GOs of any new interconnection projects be required to provide protection and control models to the TO or PC? The SRC recommends that the SDT indicate all “protection and control equipment, including auxiliary equipment” that will affect the ride-through capabilities of the generator during disturbances. The SDT should identify the auxiliary systems that the ride-through should not affect.

On page 3, under Detailed Description, the SAR calls for “A requirement that abnormal reductions in active power (i.e., tripping from protections or notable reductions from controls) are analyzed by the GO to develop a corrective action plan, if possible. Situations where corrective action plans are not able to be developed shall be reported to the TOP, BA, and RC.”

This description reads much broader than what is described in the SAR purpose. In the purpose it is directed specifically towards “fail to ride through system events”. Is the intent of the SAR scope to create a requirement to report reductions in active energy which go beyond “fail to ride through system events” and include abnormal reductions of any cause? The SRC requests the SAR DT clarify the project scope.

On the bottom of page 3, the SAR states, “Legacy facilities prior to the effective date of the standard should receive an exemption; however, resources with a commercial operation date after the effective date of the standard.” We are concerned that there will be significant amounts of IBR facilities that will be exempt from these requirements. In addition, this seems to be at odds with the“all” language contained in the last bullet on the bottom of page 2 (and as mentioned in the SRC comments above).

In 2018, a SAR was introduced and denied by the Standards Committee to correct momentary cessation of IBRs that had no such exemption because of the risks existing facilities were causing on the BES. This SAR does not propose any solutions to address that risk. We recognize that there are some IBR installations which pre-date the technology to meet the SAR purpose. However there are already numerous amounts of IBRs in operation which can adopt new technology to meet the SAR’s purpose. A blanket exemption should not be a part of the standards and instead some form of exemption process should be utilized. Further between the time this standard may be complete and the time it takes effect due to the need for regulatory approval, which may be over two years. Numerous additional new installation of IBRs would become grandfathered which certainly can meet the ride through requirements. The SRC recommends exemptions be limited to technical infeasibility.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

While EEI agrees in principal that that there have been performance issues, primarily with Solar PV Inverter Based Resources (IBRs), that need to be addressed, we do not support the retirement of PRC-024.

While there were losses of synchronous generators in some of the six disturbance reports cited in the proposed SAR, none appear to be unexpected, unusual or the result of non-compliance with PRC-024. As noted below, all of these six events linked within this SAR indicate solar PV performance problems, not synchronous generator problems.

Additionally, if the intent of the SAR is to "create a comprehensive, performance-based ride-through standard," development of a standard would need to account for retirement of other relay setting standards such as PRC-025-2 and PRC-026-1, to prevent duplicative requirements and compliance obligations.

For these reasons, we do not support the retirement of PRC-024-3. However, we offer an alternative approach in our response to question 2.

NERC 2021 California Disturbances Report (2022)

- June 24, 2021 – **Loss of 765MW of solar PV resources** (27 facilities) and 145MW of DERs (no synchronous resources lost).
- July 4, 2021 – **Loss of 605MW of solar PV resources** (33 facilities) and 46MW of DERs; 125MW; additionally, a single 125MW CT tripped due to two defective sensors as reported by the GO.
- July 28, 2021 – **Loss of 511MW of solar PV resources** (27 facilities) and 46MW of DERs (no synchronous resources lost).
- August 25, 2021 – **Loss of 583MW of solar PV resources** (30 facilities) and 212MW gas turbine tripped as a result of a correct operation of a RAS scheme. An additional gas turbine tripped during this event due to the failure of the excitation system (failed diodes). As stated in the report, the diodes were redundant but can only be detected during manual inspection. It is speculated that the redundant diodes failed as a result of the event, GO has indicated they will increase their inspections to avoid future failures.

NERC Odessa Disturbance Report (2021)

- May 9, 2021 Event – Initial fault occurred during CT startup testing when a surge arrester failed taking out one CT and causing another to run back for a total loss of 192MW. After this event **1112MW of solar PV output was lost**, in addition 36MW of output from 4 wind power plants.
- June 26, 2021 Event – Failed H-Frame structure causes the **loss of 518MW at 5 PV facilities**.

NERC San Fernando Disturbance Report (2020) July 7, 2020

- Static wire on a 230kV line failed causing the tripping of two lines on a double circuit tower. In addition, a nearby 230kV line relay mis operated. The result was the initial **loss of 205MW of solar PV output**. When trying to restore the lines, the second line tripped out causing the larger event, the **loss of 1000MW of solar PV output** (no synchronous resources lost).

NERC Palmdale Roost and Angeles Forest Disturbances Report (2019)

- April 20, 2018 (Angeles Forest) – A splice on a 500kV line failed causing a B-C phase fault which was cleared within 2.6 cycles. The fault caused the **loss of 860MW of solar PV output** in CAISO and 17MW in LADWP. In addition, a natural gas turbine tripped as a result of the fault. The report indicates the plan tripped on low fuel pressure causing the natural gas turbine to trip and the reduced output of a combined cycle steam generator to reduce output to 75MW for a total loss of 200MW. There was an additional loss of 130MW of DER output.
- May 11, 2018 (Palmdale Roost) – The disturbance was caused by a bird nest on a 500kV line that caused a line flashover (B phase to ground fault). As a result, there was a loss of **630MW of solar PV output in CAISO**, 48MW in LADWP and 33MW in IID. Additionally, there was 100MW of DER output lost (no indication of any synchronous generation lost during this event).

NERC Canyon 2 Fire Disturbance Report (2018)

- Canyon 2 Fire Disturbance, Oct. 9, 2017 – Two transmission lines faulted near Anaheim Hills, CA. The first fault occurred on a 220kV line at 12:12 PM and the second occurred at 12:14 PM on a 500kV line. The first fault resulted in the **reduction of 682MW of solar PV output**, which the second resulted in the **reduction of 937MW of solar PV output** (no indication that any synchronous generation was lost).

NERC Blue Cut Fire Disturbance Report (2017)

- On Aug. 16, 2016 AM the Blue Cut fire began in Cajon Pass, CA. As a result of the widespread fire SCE experience thirteen 500kV line faults and LADWP experienced two 287kV faults. Four of the fault events resulted in the **loss of 1,200MW of solar PV output** (no indication any synchronous generation was lost).

Likes 0	
Dislikes 0	

Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	

Ride-through is not a defined term in the NERC Glossary of Terms nor NPCC Glossary of Terms. The objective of the SAR is commendable, however the specific characteristics of the disturbances addressed by the new standard needs to be carefully defined. Usually the magnitude and duration of grid disturbances should be defined. Particular contingencies should be specified and studied to ensure those applicable reasonable foreseeable disturbances can be assessed and addressed.

Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

Regarding the 4th bullet in the “Project Scope” section, ERCOT believes the SAR should not exclude auxiliary systems that could impact the facility’s continued operation. The SDT should review the various types of auxiliary systems in use at in-scope facilities and determine whether to exclude any of them. ERCOT suggests revising the 4th bullet as follows:

This standard should address protections and controls directly focused on the generator and its prime mover (e.g., overspeed, power-load imbalance, overvoltage, phase jump, overcurrent) or at the plant level (e.g., voltage, current, frequency, phase, etc.) because they pose notable risks to BES reliability. The SDT will determine whether this ride-through standard may exclude auxiliary systems that do not impact the facility’s ability to maintain real and reactive power during a disturbance.

Regarding the 2nd sub-bullet in the “Detailed Description” section, ERCOT suggests the standard contain a requirement for a GO to report only trips or reductions in real power or improper reactive power response (trips or reductions within some threshold of the performance parameters established in the standard).

Regarding the 3rd sub-bullet in the “Detailed Description” section, ERCOT suggests clarifying the term “abnormal” to include trips and reductions in real power or improper reactive power response failing to meet the performance parameters established in the standard. Further, ERCOT suggests the SDT include a requirement for the GO to develop *and implement* a corrective action plan (CAP) or report to its TOP, BA and RC any CAP it cannot implement *due to technical infeasibility*. Finally, ERCOT suggests removing “if possible” because ERCOT’s proposed language (above) addresses situations where the GO cannot implement the CAP due to technical infeasibility.

Accordingly, ERCOT suggests modifying the 2nd and 3rd sub-bullets as follows:

- The proposed deliverable is a new NERC standard (or significant overhaul and revision of PRC-024-3) that includes the following key elements:
- ...

- A requirement for a GO to report to its TOP, BA and RC trips or reductions in real power or improper reactive power response (i.e., trips or reductions within a threshold of the performance parameters established in the standard).
- A requirement for a GO to: (a) analyze abnormal trips or reductions in real power or improper reactive power response (i.e., tripping from protections, notable reductions from controls, trips or reductions in real power or improper reactive power response failing to meet performance standards established in this standard); and (b) develop and implement a corrective action plan (CAP). If a GO cannot implement a CAP because it is not technical feasible to do so, the GO must report that fact to its TOP, BA, and RC.
- ...

Regarding the 4th sub-bullet in the "Detailed Description" section, ERCOT agrees with the SRC that the project should not exempt legacy facilities. Exempting legacy facilities will not address the reliability-related need this project addresses.

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

Please address and clearly explain the relationship between the two SARs ("Revision of relevant Reliability Standards to include applicability of transmission-connected dynamic reactive resources" approved in April, and "Generator Ride-Through Standard (PRC-024-3 Replacement)". Failure to provide this clarification will result in confusion between intents and requirements for different types of devices and may not clearly align with the earlier whitepapers and recommendations.

Additionally-please clarify that Synchronous Condensers, STATCOMs, SVCs and HVDC are not considered generator protection and control systems and should not be included in this standard. If Synchronous Condensers, STATCOMs, SVCs and HVDC are intended to be included in the standard, it needs to be revised to reflect that and include proper terminology, consideration of capability, and requirements specific to transmission-connected dynamic reactive power resources as opposed to generation resources.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter

Answer	No
Document Name	

Comment

FirstEnergy supports EEI's comments.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 1,3,6

Answer	No
Document Name	

Comment

Ameren agrees with EEI's comments. A new ride through standard should be created for IBR's only. The performance issues were with IBR's not synchronous generators.

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - Florida Municipal Power Agency - 3,4,5,6 - SERC, Group Name Florida Municipal Power Agency (FMPA)

Answer	No
Document Name	

Comment

Florida Municipal Power Agency (FMPA) supports comments submitted by NAGF.

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 1,5

Answer	Yes
Document Name	

Comment

At this point, it is hard to disagree with this project since it is still broad and vague

Likes 0	
Dislikes 0	

Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA supports revision of the current PRC-024-3 rather than creation of a new reliability standard. BPA believes the project will raise the bar on protection of BPS-connected inverter-based resources.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE agrees with the need for this project to develop a comprehensive generator "ride-through" standard in lieu of the current PRC-024's focus solely on voltage and frequency protection settings. As the September 2021 Joint Odessa Disturbance Report for Texas Events on May 9, 2021 and June 26, 2021 ("Odessa Disturbance Report") highlighted, "the systematic nature of [Inverter-Based Resource tripping or cessation] events across multiple interconnections and a wide range of facilities, many of which are recently energized, warrants significant enhancements to the NERC Reliability Standards to address gaps in BES inverter-based resources." (Odessa Disturbance Report, at 29). These recommendations included the need for developing a new generator protection and control ride-through standard to replace the current PRC-024-3 to address continued examples of widespread tripping that are not addressed by the current PRC-024-3 requirements. Texas RE appreciates that the SAR provides an approach to capture the range of performance issues (PLL loss of synchronism, subcycle ac overvoltage protection, dc reverse current, and wind converter crowbar failures) that have resulted in widespread tripping incidents across a number of interconnections, including the ERCOT Interconnection. It further recommended that NERC do so on an expedited timeframe. Texas RE notes that this call of expedited action is even more pressing given the recent tripping of significant inverter-based resources in the ERCOT Interconnection earlier this year, continuing a pattern of generator performance issues in this area. NERC has highlighted grid transformation issues as the single greatest risk to grid reliability at the current time. Texas RE appreciates the SDT's important role, care, and commitment to addressing these performance issues in this project.	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
The NPCC Regional Standards Committee agrees with the proposed scope as described in the SAR.	
Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
The Project 2020-02 webpage reflects that the initial project SAR, posted for industry comments on 3/30/2020, was revised and subsequently accepted by the NERC Standards Committee on 4/20/2022. A redline of the SAR accepted by the Standards Committee in April 2022 vs. the initial SAR posted in March 2020 is posted on the project page. It appears that a different Project 2020-02 SAR (prepared by NERC executives and staff) was presented to and accepted by the NERC Standards Committee a month later, on 5/18/2022. We suggest that a redline of the SAR accepted by the Standards Committee in May 2022 vs. the SAR accepted by the Standards Committee in April 2022 (or the initial SAR posted in March 2020) be added to the project page. It is not clear why the SAR submitted by the Chair of the System Analysis & Modeling Subcommittee and accepted by the Standards Committee in April 2022 was "abandoned" a month later to be replaced by the SAR submitted by NERC.	
Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Isidoro Behar - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Provide any additional comments for the drafting team to consider, if desired.

LaKenya VanNorman - Florida Municipal Power Agency - 3,4,5,6 - SERC, Group Name Florida Municipal Power Agency (FMPA)	
Answer	
Document Name	
Comment	
Florida Municipal Power Agency (FMPA) supports comments submitted by NAGF.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	
Document Name	
Comment	

While FirstEnergy does agree that an assessment needs to be conducted to ensure reliability of the BES due to the changing mix of generating resources, we do not agree that a reliability standard should result in additional penalties for a GO if generating capacity requirements are not met due to a fuel shortage caused by unforeseen events. FirstEnergy generators already participate in the PJM capacity market and are required to provide generating capacity based on summer ICAP testing results. A generator is assessed financial penalties by PJM if it cannot meet its generating capacity requirements and therefore, we caution against a double jeopardy situation.

We also suggest the RC and BA, not the GO, should be responsible for developing a CAP if generation capacity demands are not met during periods of constrained resources. It is the responsibility of the Transmission Grid Operator (e.g., PJM), not the GO, to ensure that adequate generating resources are available during periods of constrained resources. Operating characteristics of IRBs are the cause of constrained resources and mitigation actions over-and-above PJM generating capacity requirements should not be placed on fossil generation resources.

Further, FirstEnergy supports EEI's comments, which states:

As an alternative to the proposed PRC-024 SAR, EEI suggests that a new SAR be developed to address performance issues specifically affecting IBRs. This new SAR could leverage key scope items from this proposed SAR to create a new performance- based NERC Reliability Standard that is focused on IBRs. As a suggested scope, we propose modifying this SAR as follows:

-- Trips or reductions in active power that occur because the IBR does not operate as expected (excludes cloud cover, setting sun, etc.), but not associated with protection system trips, (PRC-004 already addresses protection system tripping) are to be analyzed by the GO to develop a corrective action plan. Situations where an issue cannot be corrected, the GO shall develop a report detailing the limitations of the IBR and provide it to the responsible TOP, BA, and RC.

-- Momentary cessation, or temporary ceasing of current injection in response to grid disturbances, is deemed unacceptable for BES generating resources. Inverter-based generating resources employing momentary cessation shall develop a corrective action to mitigate its use unless the issue cannot be corrected. Legacy facilities prior to the effective date of the standard should receive an exemption; however, resources with a commercial operation date after the effective date of the standard shall be required to eliminate the use of momentary cessation during system transient disturbances where the system voltage or frequency falls within the "No Trip Zone" provided in PRC-024-3, which is subject to enforcement October 1, 2022.

-- Include the development of new terms to address terms specific to IBRs or where commonly used industry terms have created some confusion for IBR owners. E.g., No Trip Zone, trip, momentary cessation, and any other relevant terms that may require clarification within the NERC Glossary of Terms.

-- Prolonged IBR controller interactions that impede the ability of the resource to respond dynamically to the grid disturbance and preclude the ability to provide essential reliability services are deemed unacceptable and should be addressed by a corrective action plan. In situation where the GO has determined the issue cannot be corrected, a report shall be developed detailing the IBR limitation and provide it to the responsible TOP, BA and RC.

--If the TOP, BA, or RC inform the GO/IBR owner of a tripping occurrence, cessation event, or IBR controller interactions that are not reported or otherwise identified by the GO/IBR Owner, the responsible GO shall be responsible for analyzing the facility's performance during the event, developing a corrective action plan, and making this available to the TOP, BA, and RC or in the situation where the issue cannot be corrected, informing the TOP, BA and RC.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

The current PRC-024-2, "No Trip Zone" is very clear and easy to understand for frequency and voltage parameters. The SAR Requesters' logic and SAR details appear to be pretty thorough, with the exception of replacing the "No Trip Zone" with "fault ride-through capabilities" as proposed in the revised SAR (dated 4/28/2022). We recommend the SAR Requesters/SAR Drafting Team expand on the proposal to eliminate "No Trip Zone" requirements, and expand the discussion regarding the replacement "fault ride-through capabilities".

The revised SAR language seems to suggest that synchronous generating resources suffer from mis-trips and mis-application of the standard due to deficiencies identified in PRC-024-3 to the same degree that inverter-based resources do. None of the six disturbance reports cited as technical justification for the SAR reference loss of synchronous generation caused by an inadequate or missing requirement within PRC-024-3. From a reliability perspective, while GO/GOPs of IBRs stand to benefit from a replacement/overhaul of PRC-024-3, there is no clear benefit to GO/GOPs of traditional synchronous generating resources. We recommend that the SAR language be revised to clearly delineate the current issues with synchronous generation resources and the current issues with IBRs driving this proposed standard modification, and how the changes are impacting each technology.

The proposed scope explicitly excludes auxiliary systems with the rationale that "abnormal performance or unexpected tripping of these protections do not pose a systemic BES reliability risk" (Page 3, "Project Scope", 4th bullet point). Components of auxiliary systems like unit auxiliary transformers (UATs) typically feature protection that are capable of taking a generator offline. Given this, there may be a heightened reliability risk if auxiliary equipment are not subject to the same requirements of the proposed standard as generator protection and controls. Auxiliary transformers (and BES GSUs) were added to the applicable equipment scope in the revision from PRC-024-2 to PRC-024-3, so an explanation is requested for why this inclusion is not being preserved.

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	
Document Name	

Comment

Please clarify momentary cessation of "current injection during BPS fault events."

Re: this SAR please explain if current injection refers to active current, reactive current or both?

Likes 0	
Dislikes 0	

Response

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT provides the following additional comments:

The SAR specifically identifies protections/controls posing risks to BES reliability. The proposed standard should not specify criteria for every potential quantity that may trigger a trip. Specifying voltage and frequency envelopes should suffice. Operating within those envelopes should not trigger any other plant control or protection to trip.

Not having high-resolution data limits the ability to identify the root cause of the events referenced in the SAR. High-resolution data, including data from phasor measurement units (PMUs), digital fault recorders (DFRs), and inverter-based oscillography, is critical to identify the root cause of disturbance events and, as such, necessary to develop a CAP. Additionally, high resolution data allows a better understanding of the interaction between local wind turbine ride-through control versus the facility plant controller. ERCOT believes this SAR should require data recording relating to voltage ride through and to add appropriate language to PRC-002-2.

Finally, ERCOT suggests the SDT consider IEEE 2800 when drafting a proposed standard.

Likes 0	
Dislikes 0	

Response

Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	
Document Name	
Comment	
In place of GOs only notifying the PC and TP when they can't meet the ride-through requirement or upon request, GOs should be required to periodically (annually?) provide, or confirm no changes to, their generator protection trip settings to the PC and TP.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	

If an attempt is made to define the ride through then it should consider the Bulk Electrical System (BES) as well as all the applicable/foreseeable generating resources that can potentially impact the BES.

A suggestion is made to use, consistently, just the Bulk Electrical System (BES) acronym and not to loosely interchange with BPS whose meaning is different than BES in the NPCC region (Bulk Power System as determined by Directory #1/A#10 methodology)

The SAR mentions that "Generator ride-through is a foundational essential reliability service.". To date the "ride-through" is not defined as a reliability service the same way we understand the following:

- **Frequency support** - provided through the combined interactions of synchronous inertia and frequency response, as services to arrest the decline in frequency and eventually return the frequency to the desired level
- **Ramping and Balancing** – provided through dispatch by the generating units with active power management capability and ability to respond to dispatch signals
- **Voltage Support** - provided through planning and confirmation testing of reactive power sufficiency per unique characteristics of their respective BA systems.

Having generating resources with ride-through capabilities are not a guarantee that the generating units will remain connected to the grid even less of a guarantee they will provide BES support (reliability services during BES disturbance) since BES support is also a:

- Function of static and dynamic reactive power reserve capabilities to regulate voltage at those respective points in the system
- Function of levels of conventional synchronous inertia for respective balancing area/interconnection, and initial frequency deviation following the largest contingency event for the interconnection

This SAR should only be applicable to the protection/protective functions that trip the protected equipment in response to a BES disturbance, where the disturbance conditions do not pose a risk of damage to the associated equipment, whose protection must be prioritized (similar with PRC-025-2).

Equipment protection does not amount nor have a simultaneous compounded effect on grid reliability.

The SAR statement related to the cost impact associated to this Project being expected to be minimal, should not be treated as an accurate statement as long as the entire scope of the project has not even been identified.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

As an alternative to the proposed PRC-024 SAR, EEI suggests that a new SAR be developed to address performance issues specifically affecting IBRs. This new SAR could leverage key scope items from this proposed SAR to create a new performance- based NERC Reliability Standard that is focused on IBRs. As a suggested scope, we propose modifying this SAR as follows:

- Trips or reductions in active power that occur because the IBR does not operate as expected (excludes cloud cover, setting sun, etc.), but not associated with protection system trips, (PRC-004 already addresses protection system tripping) are to be analyzed by the GO to develop a corrective action plan. Situations where an issue cannot be corrected, the GO shall develop a report detailing the limitations of the IBR and provide it to the responsible TOP, BA, and RC.
- Momentary cessation, or temporary ceasing of current injection in response to grid disturbances, is deemed unacceptable for BES generating resources. Inverter-based generating resources employing momentary cessation shall develop a corrective action to mitigate its use unless the issue cannot be corrected. Legacy facilities prior to the effective date of the standard should receive an exemption; however, resources with a commercial operation date after the effective date of the standard shall be required to eliminate the use of momentary cessation during system transient disturbances where the system voltage or frequency falls within the “No Trip Zone” provided in PRC-024-3, which is subject to enforcement October 1, 2022.
- Include the development of new terms to address terms specific to IBRs or where commonly used industry terms have created some confusion for IBR owners. E.g., No Trip Zone, trip, momentary cessation, and any other relevant terms that may require clarification within the NERC Glossary of Terms.
- Prolonged IBR controller interactions that impede the ability of the resource to respond dynamically to the grid disturbance and preclude the ability to provide essential reliability services are deemed unacceptable and should be addressed by a corrective action plan. In situation where the GO has determined the issue cannot be corrected, a report shall be developed detailing the IBR limitation and provide it to the responsible TOP, BA and RC.
- If the TOP, BA, or RC inform the GO/IBR owner of a tripping occurrence, cessation event, or IBR controller interactions that are not reported or otherwise identified by the GO/IBR Owner, the responsible GO shall be responsible for analyzing the facility’s performance during the event, developing a corrective action plan, and making this available to the TOP, BA, and RC or in the situation where the issue cannot be corrected, informing the TOP, BA and RC.

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2

Answer	
Document Name	

Comment

The current PRC-024 standard was written with conventional (rotating) generators in mind. Conventional generators are quite sensitive to generator speed (frequency) and abnormal speeds can damage, i.e. lower the life of, turbine blades. Hence the further away the frequency deviates from 60 Hz, the shorter the duration allowed for “no-trip.” In contrast, Inverter-Based Resources (IBRs) don’t have rotating parts whose speed is tied to their connection to the grid. Since IBRs are not affected by deviations in system frequency as much as conventional (rotating) generators, the SRC requests the PRC-024 SAR be revised to include a recognition for this difference as there may be different ride-through requirements for IBRs than conventional generators within the same interconnection.

In addition, to aid in industry implementation, the SRC requests the SAR include the requirement to provide some real-world examples; e.g. in Technical Rationale, to illustrate how proposed standard requirements will ensure both IBRs and conventional generators are able to ride-through faults and how, had they been in place, would have addressed past issues of inadequate ride-through capability.

Finally, the SRC requests that the SAR ask to expand the requirement in selecting a Standards Drafting Team (SDT) that is stated in Question 5 on the SAR form. The SRC agrees it is important to include entities that the standard will apply to, but in addition, entities who have a need for the information or bear responsibility to reliably operate within the bounds of the standard (even if the standard does not directly apply to them from a requirement and compliance standpoint), should also be included. The requirements set in any standard are intended to ensure the reliability of the BES as a whole which all registered entity functions have an impact or interest in. This should apply to any and all SARs and the SRC would like to ask NERC to address a change in the SAR form in the future.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	

Comment

The NAGF notes that the SAR references the term Bulk Power System (BPS) and Bulk Electric System (BES) through the SAR document. Recommend consistent use of the terms in the Purpose, Project Scope, and Deliverables sections.

In addition, the NAGF notes that the SAR is not consistent with regard to retiring and replacing PRC-024-3 (Purpose or Goal Section, first sentence). Bullet #1 of the Project Scope states “Retire PRC-024-3, and create a new PRC standard or completely overhaul and replace the existing PRC-024 standard.” Bullet #1 of the Detailed Description of the Project Deliverables states “The proposed deliverable is a new NERC standard (or significant overhaul and revision of PRC-024-3) that includes…).

Likes 0	
Dislikes 0	

Response

John Pearson - ISO New England, Inc. - 2	
Answer	
Document Name	

Comment

Below are proposed changes for the "proposed deliverable" section of the SAR.

The proposed deliverable is a new NERC standard (or significant overhaul and revision of PRC-024-3) that includes the following key elements:

A performance-based approach to generator ride-through rather than an equipment settings standard. The new standard shall include requirements that BES resources shall ride through grid disturbances and include quantitative measures (see below) on expectations for ride-through that address all possible causes of tripping and power reductions from BES generating resources (particularly generator, turbine, inverter, and all plant-level protection and controls, including auxiliary systems).

A reporting requirement that all trips or abnormal reductions in power output are reported by the GO to the TOP, BA, and RC.

A requirement that abnormal reductions in active power (i.e., tripping from protections or notable reductions from controls) are analyzed by the GO and shall be reported to the TOP, BA, and RC.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment

Minnesota Power supports EEI's comments for this question.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	
Document Name	
Comment	
AZPS suggests PRC-024 should remain unchanged as it applies to synchronous generators and that a new SAR be developed to address performance issues specifically affecting IBR's that are interconnected to the BES.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #2.	
Likes 0	
Dislikes 0	
Response	
Isidoro Behar - Long Island Power Authority - 1	
Answer	
Document Name	
Comment	

The stated purpose of this SAR is to retire PRC-024-3 and replace it with a performance-based ride-through standard that ensures generators remain connected to the BPS during system disturbances. Additionally, the SAR will focus on the generator protection and control systems that can result in the reduction or disconnection of generating resources during these events.

As part of the development of the performance based standard or overhaul of PRC-024-3, it is recommended that the standard drafting team include and highlight specific references to the relevant IEEE Standard P2800-2022 clauses and to relevant FERC Orders (related to ride-through), where applicable. It will be important for stakeholders to discern similarities and differences between the new or revamped standard and these existing references.

We can offer another comment, related to PRC-024-3, for consideration in the development of a performance based standard or overhaul of PRC-024-3.

For PRC-024-3 applicability section 4.1.2, it mentions that it is for Transmission Owners in the Quebec Interconnection only. There are Transmission Owners outside the Quebec Interconnection that own BES generator step-up transformers (GSUs). Is PRC-024-3 intended to be applicable to Transmission Owners that own BES GSUs that are outside the Quebec Interconnection? If so, perhaps the "in the Quebec Interconnection only" should be removed from applicability section 4.1.2 in the next revision.

Likes 0	
Dislikes 0	

Response

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3

Answer	
Document Name	

Comment

MidAmerican supports MRO NSRF and EEI comments.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments

Answer	
Document Name	

Comment

PG&E agrees with the comments and suggested scope provided by EEI; a new SAR should be developed to address the unique performance characteristics of IBRs.

Likes 0	

Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	

Southern Company disagrees with the "Cost Impact Assessment". We feel that generation resources will need to install high speed recorders to capture data on electrical events that occur and the reaction of generation resources to said electrical event. These high speed recorders will be essential for any requirement for analysis and development of corrective action plans. Southern Company purports that it will be costly to engineer, procure and install this equipment.

Noting that IBR components capable of providing the performance characteristics are just now beginning to be developed and offered by vendors coupled with regulatory requirements for providing that performance will certainly cause equipment suppliers to increase costs to the users.

With the cause of the concern raised in this SAR being the system disturbance, perhaps a more beneficial result can be achieved by investigating the causes of the system disturbances that have been resulting in natural responses of the IBR and synchronous machine based generating stations. Our experience has been that most of the existing IBR systems that operate perfectly given a network with no disturbances.

The recent development and adoption of IEEE P2800 (Standard for Interconnection and Interoperability of Inverter-Based Resources Interconnecting with Associated Transmission Electric Power Systems) is nowhere to be found in the SAR as a resource. It is Southern Company's opinion that IEEE P2800 be fully understood and used by the SDT as a resource of what operational capability limits exist for IBRs. P2800 goes into many of the aspects that IBRs face from a performance perspective. A common issue with IBRs is loss of synchronism because of the voltage phase angle jump that can occur with system disturbances. A voltage phase angle shift jump can occur with the voltage magnitudes still within the no-trip zone, leading to momentary cessation because of loss synchronism of the IBRs synchronizing phase-locked loop control function.

The Functional Entities identified in the PRC-024 standard have no control what-so-ever of the design and performance characteristics of the Inverter Based Resource manufacturers equipment. This leads to GOs attempting to coerce the IBR manufactures after-the-fact to change equipment settings and parameters to comply with operational situations that they are either not designed to perform to or, due to the technical nature of the IBR generation process, cannot perform to. To move to a performance based standard and holding the GO accountable for the design performance of the IBRs is futile at best. The only performance criteria defined in the SAR so far is impossible for all situations, and that is “A clear requirement that momentary cessation, or temporary ceasing of current injection during BPS fault events, is deemed unacceptable performance for BES generating resources”.

Likes 0	
Dislikes 0	

Response

Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	
Document Name	

Comment

Xcel Energy supports the comments offered by EEI, NAGF, and MRO NSRF.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO

Answer	
Document Name	

Comment

The MRO NSRF disagrees with the “Cost Impact Assessment”. The MRO NSRF feels that generation resources will need to install high speed recorders to capture data on electrical events that occur and the reaction of generation resources to said electrical event. These high speed recorders will be essential for any requirement for analysis and development of corrective action plans. The MRO NSRF believes it will be costly to engineer, procure and install this equipment.

The MRO NSRF recommends replacing all instances of bulk power system (BPS) with Bulk Electrical System (BES) to ensure proper scoping of the SAR.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	

Document Name	
Comment	

Momentary Cessation Requirements for Existing Generators

While Texas RE appreciates the proposed SAR's focus on generator performance issues in general and momentary cessation issues in particular, Texas RE is concerned that the current proposed SAR would exempt facilities in commercial operation prior to the effective date of the new PRC-024-3 requirements from "the use of momentary cessation within 'ride through envelopes' (e.g., the existing PRC-024 "No Trip Zone"). (PRC-024 Standard Authorization Request, at 3-4). The Odessa Disturbance Report observed that momentary cessation issues resulted in generation loss, along with tripping issues inside of facilities during the event (Odessa Disturbance Report, at 7). In particular, the Odessa Disturbance Report noted: "legacy inverter momentary cessation setting with plant-level controller interactions prohibited quick active power recovery." (Odessa Disturbance Report, at 33). The report also noted other forms of momentary cessation issues, including settings that produced fixed reactive power injection with "no ability to control voltage post-contingency." (Odessa Disturbance Report, at 20). It further noted that "[t]his type of behavior was not known by ERCOT prior to the event analysis nor is this type of behavior supporting the BPS post-fault." (Id.).

Given the significance of these momentary cessation issues during the Odessa Disturbance event and other events over the past six years, Texas RE encourages the SDT to not limit momentary cessation performance requirements exclusively to new generation facilities. While Texas RE expects the SDT to move expeditiously with this project, Texas RE notes that the final revised standard may not be effective for several years. As a result, not only would existing generators not be covered by any momentary cessation requirements, but a number of planned generation resources would be similarly exempt. Given the growing role of inverter-based resources in the ERCOT Interconnection and others, this could result in a significant reliability gap.

Texas RE notes that momentary cessation issues are currently documented in NERC Reliability Guidelines (E.g., Reliability Guideline: BPS-Connected Inverter-Based Resource Performance (Sept. 2018) (2018 IBR Performance Guidelines). These existing guidelines note that "Existing and newly interconnecting inverter-based resources should eliminate the use of momentary cessation to the greatest possible extent." (2018 IBR Performance Guidelines, at 11). It is also important to note that one of the key findings in the Odessa Disturbance Report is that while these reliability guidelines are widely viewed and shared, entities are "not comprehensively adopting the recommendation(s) contained in those materials." (Odessa Disturbance Report, at vi). In short, a new Reliability Standard is required.

Texas RE acknowledges it may take time to review and implement settings to avoid certain momentary cessation-type performance issues. As the 2018 IBR Performance Guidelines note, however: "Existing resources may have hardware and/or software limitations based on a design philosophy using momentary cessation, and it may not be feasible to eliminate its use. For equipment limitations that cannot be addressed, PRC-024-2 Requirement R3.1 states that '[t]he [GO] 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.'" (2018 IBR Performance Guidelines, at 11-2). The drafting team could consider approaches that permit legacy systems lacking functionality to avoid momentary cessation issues to document those limitations for any new momentary cessation requirements developed in this project in a manner similar to the process currently provided in the existing PRC-024-3 Requirement R3.1.

Enhanced Communication Requirements

In addition to considering the incorporation of momentary cessation and other performance notification requirements as appropriate, Texas RE recommends the drafting team consider creating a new requirement for the GO to notify the GOP, in addition to the TOP, BA, and RC, regarding abnormal tripping. Since COM-001 and COM-002 do not include GO communications, an additional requirement for the GO to notify the GOP would be helpful for the GOP to have the information to communicate any GO issues via COM-001 and COM-002.

Likes 0	
Dislikes 0	

Response

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

Although PRC-024-3 is not applicable to BPA by registration, the PRC-024-3 Requirements R3 and R4 do impact BPA as a Transmission Planner and Planning Coordinator and will have substantial impact to BPA's interconnection requirements. BPA encourages the drafting team to address the inconsistencies in format of how TPs and PCs receive the data. Data consistency will support more efficient and effective modeling of relay settings

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	
Document Name	

Comment

No additional comments. Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5,6

Answer	
Document Name	

Comment

N/A

Likes 0	

Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
All protection and control system functions that will be in scope should be specifically listed in the standard. Guidance on complying with ride-through requirements should be provided by including detailed examples. A sufficient phase-in period should be part of the implementation plan to allow GOs time to achieve the additional coordination that will be required. Based on the defined project scope the new standard will enforce that unexpected trips, abnormal trips and reductions in power are reported to the pertinent entities. The term reduction of power needs to be defined since it is open for interpretation. Furthermore, this reporting-out could infringe on current standards like PRC-004.	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1,3,6	
Answer	
Document Name	
Comment	

The Cost Impact Assessment states incremental cost impact which is not correct. Additional analyses and design changes are likely based on the widespread loss of generating resources observed.

Likes 0	
Dislikes 0	

Response

Consideration of Comments

Project Name: 2020-02 Modifications to PRC-024-3 (Generator Ride-through) | Standard Authorization Request
Comment Period Start Date: 5/31/2022
Comment Period End Date: 7/14/2022

There were 40 sets of responses, including comments from approximately 103 different people from approximately 72 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, contact Director, Standards Development Latrice Harkness (via email) or at (404) 858-8088.

Questions

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope, please provide your recommendation and explanation.

2. Provide any additional comments for the drafting team to consider, if desired.

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
DTE Energy - Detroit Edison Company	Adrian Raducea	3,5		DTE Energy - DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison	5	RF
					patricia ireland	DTE Energy	4	RF
WEC Energy Group, Inc.	Christine Kane	3,4,5,6		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
Tacoma Public Utilities (Tacoma, WA)	Jennie Wike	1,3,4,5,6	WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Marc Donaldson	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Florida Municipal	LaKenya VanNorman	3,4,5,6	SERC		Chris Gowder	Florida Municipal	5	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Power Agency				Florida Municipal Power Agency (FMPA)		Power Agency		
					Dan O'Hagan	Florida Municipal Power Agency	4	SERC
					Carl Turner	Florida Municipal Power Agency	3	SERC
					Jade Bulitta	Florida Municipal Power Agency	6	SERC
FirstEnergy - FirstEnergy Corporation	Mark Garza	1,3,4,5,6		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Tricia Bynum	FirstEnergy - FirstEnergy Corporation	6	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Pacific Gas and Electric Company	Michael Johnson	1,3,5	WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC
					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					James Mearns	Pacific Gas and Electric Company	5	WECC
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Jim Howell	Southern Company - Southern Company Services, Inc. - Gen	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Harish Vijay Kumar	IESO	2	NPCC
					David Kiguel	Independent	7	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC
					Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
					Nurul Abser	NB Power Corporation	1	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC
					Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Quintin Lee	Eversource Energy	1	NPCC
					John Pearson	ISONE	2	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro-Quebec	2	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC

1. *Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope, please provide your recommendation and explanation.*	
Brian Lindsey - Entergy - 1,3,6	
Answer	No
Document Name	
Comment	
Should add new R5 to PRC-024-3: "Generator Owners shall analyze and have a corrective action plan (if possible), and report to necessary entities any failure to ride through a system event."	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team will take this into consideration when drafting the SAR.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
The proposed standard should cover “tripping” and not include “reductions”, as the specified level can be subjective.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The team has decided to not include synchronous generators in the SAR.	

Kimberly Turco - Constellation - 5,6	
Answer	No
Document Name	
Comment	
Constellation does not agree with the proposed scope as the scope is far reaching into multiple standards not just PRC-024-3 and the impact to those standards is not clearly defined. Kimberly Turco on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you. This comment is vague and the team is unable to provide a response.	
Alison Mackellar - Constellation - 5,6	
Answer	No
Document Name	
Comment	
Constellation does not agree with the proposed scope as the scope is far reaching into multiple standards not just PRC-024-3 and the impact to those standards is not clearly defined. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you. This comment is vague and the team is unable to provide a response.	

Thomas Foltz - AEP - 3,5,6	
Answer	No
Document Name	
Comment	

AEP agrees with the concerns related to IBRs and the performance issues that have been previously noted but we do not agree that PRC-024 should be revised or replaced with ride-through obligations added for synchronous generation. AEP recommends that PRC-024 be retained as it currently is, and recommends creation of a new standard containing ride-through obligations for IBRs only. AEP does not see a reliability justification for developing ride-through obligations for synchronous generation and advises against any efforts to do so since, as also noted by EEI, such units have been seen to perform well in the various cited events.

The following comments are offered in the event that the SDT develops obligations for both synchronous generation and IBRs (contrary to our recommendation above).

The fourth bullet of the SAR's Project Scope states "protections and controls directly focused on the generator and its prime mover (e.g., overspeed, power-load imbalance, overvoltage, phase jump, overcurrent) or plant-level (e.g., voltage, current, frequency, phase, etc.) have posed notable risks to BES reliability." AEP does not agree with the proposed inclusion of overspeed and power-load imbalance, as both must be present to protect against equipment damage. Even if their presence could at times pose a reliability risk to the system, these protective functions need to be retained for the unit's own protection and continuing availability. AEP recommends removing overspeed and power-load imbalance from the SAR.

Requirement R3 in the current version of PRC-024 requires the Generator Owner to "document each known regulatory or equipment limitation that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice." Care should be taken to retain this provision in any new or revised standard.

Likes 0	
Dislikes 0	
Response	

Thank you for the comment. The SAR has the option to create a new standard. This (and R3) will be passed along for consideration by standard drafting team. The team has addressed this comment in the redlined SAR to reflect the suggested changes.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
The scope states generator overcurrent and plant-level current should be addressed in this standard. Overcurrent is addressed by PRC-025. It does not seem right to also include current in this standard. Other than the inclusion of overcurrent, the scope seems reasonable.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The team agrees that there is possible overlap with PRC-025 if overcurrent related trips are included in the ride-through standard. As such, the team has modified the SAR to reflect the fact that PRC-025, and other selected relay setting standards, may be impacted by the new standard and may need to be revised.	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO	
Answer	No
Document Name	
Comment	
The MRO NSRF in general agrees with both the concept and scope of this SAR. However, the MRO NSRF is voting no due to the following concerns: 1. *A reporting requirement that all trips or reductions in power output are reported by the GO to the TOP, BA, and RC.*	

The MRO NSRF disagrees with this deliverable. The Reliability Coordinator (RC), Balancing Authority (BA) and Transmission Operator (TOP) should be responsible for determining the magnitude threshold and duration-of-time threshold for the Generator Owner (GO)/ Generator Operator (GOP) to report trips or reductions in power output. This will ensure that the RC, BA & TOP are not burdened by notifications for trips/reductions that do not affect the Bulk Electrical System (BES) and ultimately take the RC's, BA's & TOP's attention away from matters of higher priority for ensuring the reliability of the BES. In addition, it is the NSRF belief that the RC, BA & TOP currently has the ability request information about trips or reductions in power output from the GO/GOP under the regulatory framework of NERC Reliability Standard IRO-010-4 Reliability Coordinator Data Specification and Collection & NERC Reliability Standard TOP-003-4 - Operational Reliability Data.

Further, reductions in power will occur for a wide variety of reasons such as clouds passing over or the setting of the sun at a solar generation facility, a drop in wind speed at a wind generation facility, wet coal, changes in condenser circulating water temperature or discharge water temperature limits at a thermal plant, starting an additional large fan or pump, inlet air temperature changes to gas turbines, reduced water flow at a hydro plant – none of these causes of power reduction would have any relation to PRC requirements and no additional reporting other than that required by existing NERC Standard IRO-010 & TOP-003 requirements should be necessary. The MRO NSRF believes this deliverable should say "A reporting requirement that all trips or reductions in power output in response to grid disturbances are reported by the GO as required by the applicable TOP, BA, and RC."

2. *A requirement that abnormal reductions in active power (i.e., tripping from protections or notable reductions from controls) are analyzed by the GO to develop a corrective action plan, if possible. Situations where corrective action plans are not able to be developed shall be reported to the TOP, BA, and RC.*

The MRO NSRF disagrees with this deliverable. The MRO NSRF believes that the 'trip' portion of this deliverable is already an enforceable requirement under the regulatory framework of NERC Reliability Standard PRC-004-6 - Protection System Misoperation Identification and Correction.

As written, '*notable reductions from controls*', lacks the detail required to provide a standard drafting team (SDT) with proper direction to develop a requirement(s). As this Standard Authorization Request (SAR) relates to dynamic ride-through performance of generators the MRO NSRF would request that the SAR SDT add an example magnitude threshold and duration-of-time threshold for 'notable reductions from controls'. Adding the additional information will prevent any developed requirement(s) from overreaching beyond the intention of this SAR.

3. *A clear requirement that momentary cessation, or temporary ceasing of current injection during BPS fault events, is deemed unacceptable performance for BES generating resources. Inverter-based generating resources employing momentary cessation shall*

develop a corrective action to mitigate its use. Legacy facilities prior to the effective date of the standard should receive an exemption; however, resources with a commercial operation date after the effective date of the standard (and possibly the PRC-024-3 implementation date) shall be required to eliminate the use of momentary cessation within “ride through envelopes” (e.g., the existing PRC-024 “No Trip Zone”).

The implementation date for NERC Reliability Standard PRC-024-3 — Frequency and Voltage Protection Settings for Generating Resources (NERC PRC-024-3) is October 01, 2022. As stated by the SAR requestors:

• “The existing PRC-024-3 is an equipment settings standard focused solely on voltage and frequency protection. However, this standard is serving little to no value for ensuring BPS-connected inverter-based resources remain connected and supporting the BPS during grid disturbances.”

• “The purpose of this SAR is to retire PRC-024-3 and replace it with a performance-based ride-through standard that ensures generators remain connected to the BPS during system disturbances.”

• “Retire PRC-024-3, and create a new PRC standard or completely overhaul and replace the existing PRC-024 standard.”

Based on these statements the MRO NSRF believes all generators with a commercial operation date prior to the effective date of requirements to be developed based on this SAR should not have to comply or retrofit. It is clear that any requirements developed based on this SAR will be different from the requirements of NERC PRC-024-3 and therefore the generators that need to comply should be adjusted accordingly.

4. The performance-based standard should include documented equipment limitation exemptions similar to NERC PRC-024-3 R3 and these should apply to all generator types rather than just carving out an exemption for the application of momentary cessation on legacy inverter-based resources (IBR) existing prior to the effective date of the standard (and possible the PRC-024-3 implementation date). For example, if an existing turbine has frequency limitations that do not meet the requirements of the new ride-through standard, no corrective action plan should be necessary should the turbine trip in response to a frequency excursion outside of its capability. There appears to be nothing in the SAR that addresses limitations of existing equipment other than that of legacy IBRs applying momentary cessation.

5. The MRO NSRF believes that there is little justification for retiring NERC PRC-024-3 for synchronous generators and that any new standard should be focused on IBR performance issues. If the scope is to “create a comprehensive, performance-based ride-through standard with the purpose of ensuring BES generating resources remain connected and providing essential reliability services during grid disturbances”, why would only PRC-024-3 be considered for retirement rather than to include the retirement of other relay setting

standards such as PRC-025-2, which has the purpose to assure that load responsive relays are set to prevent unnecessary tripping during system disturbances, and/or the elimination of GO applicability in PRC-026-1, which has the purpose to ensure that load-responsive relays are expected to not trip in response to stable power swings during non-Fault conditions? The MRO NSRF believes that if a truly comprehensive performance-based ride-through standard is created, then the regulatory burden of other relay setting standards pertaining to how generator protection responds to grid disturbances should be eliminated by retiring PRC-025-2 and eliminating the applicability of PRC-026-1 to Generator Owners. It seems that a comprehensive generator ride-through standard would apply to not only 24, 27, and 59 functions (PRC-024-3) but would also include trips of generating resources in response to 21, 50, 51, 51VR, 51VC, 67 (PRC-025-2) and/or 21, 40, ,50, 51, 78 (PRC-026-1) function operations in response to grid disturbances.

Further, and accounting for the aforementioned comments, the MRO NSRF recommends the drafting team consider whether retiring PRC-024-3 and replacing it with a performance-based ride-through standard may change, for example, the Generator no trip zones settings. This action would potentially affect PRC-006, and the SAR should open its scope to contemplate potential changes to that standard, and any other affected standard, if needed. This comment is to ensure the drafting team crafts a SAR with the necessary scoping parameters to make changes to associated standards as needed.

6. *A clear requirement that prolonged plant controller interactions that impede the ability of the resource to dynamically respond to the grid disturbance and preclude the ability to fully provide essential reliability services are deemed unacceptable and should be addressed by a corrective action plan.*

This requirement seems to be focused on eliminating some of the undesirable IBR performance issues, but the wording of this deliverable could be interpreted to apply to integrated plant or unit protection schemes that may indeed “impede the ability of the resource to dynamically respond to grid disturbances” but are designed to protect the boiler or nuclear reactor from pressure or level excursions, steam turbines from overspeed, operation at resonant frequencies or moisture intrusion, etc. GOs should be able to protect their equipment from catastrophic damage without having to implement a corrective action plan should these protection or control features impede dynamic response to grid disturbances.

Likes 1	Southern Indiana Gas and Electric Co., 3,5,6, Todd Anna
Dislikes 0	

Response

1. The applicability of the defining of a thresh hold will be considered where applicable when drafting the standard in the performance criteria. The SAR has been has been modified to reflect this quote. The information will be passed along to the standard drafting team.
2. The team will look at PRC-004 and make sure there is no overlap, this SAR focusing on performance criteria IBRs. Thank you for the proposal this will be reviewed in the standard drafting process when applicable.
3. This will be passed on to the drafting team, please refer to NAGF response to comment regarding legacy PRC-024 policy.
4. Refer to previous comment.
5. The team has considered the comments and have modified the SAR to reflect these specified standards and any other applicable standards.
6. Please refer to comment 3D in NAGF response to comment. The redlined SAR reflects this change.

Israel Perez - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

We do not agree with the proposed scope described in the SAR, as more clarification of expectations and deliverables are needed. The proposed scope is not clear if the changes would require the installation of additional protection devices to our generators or switchyards and if additional DCS/computer points need to be monitored. Would the changes require third-party generator studies and at what frequency? We are concerned that these changes, which are still unclear, will require additional preventative tasks and specialized personnel necessary to perform these tasks. If the disturbance in the grid is large enough, wouldn't it be better for our generators to disconnect and/or trip to prevent equipment damage? A unit/generator restart would have a faster turnover and would be more efficient than having a damaged generator that motored because we couldn't disconnect it from the large disturbance of the grid.

In addition, it seems that we must wait until "performance" metrics are outlined and how metrics meet baseline criteria. The reference documents outline some of the criteria for measurement and submittal methods but not the full metric. The "ride through" criteria is mentioned, as a "no trip zone" in the attached document but not a clear definition of achieving that target. The process for defining the performance characteristics of a generation resources is not specified other than a system strength specification which we believe would

require a separate criterion for each BES bus depending on the generation in the vicinity. It would be difficult to define and enforce and even more difficult to monitor. The events in southern California revealed that generation went into a current cessation mode during a frequency/voltage excursion and PRC-024-3 covers this issue. The event would expand the scope from generation ride through to include any event where generation was reduced or removed from service for say auxiliary systems being removed from service. This subject might fall under PRC-004. If the tripping or reduction in generation is entirely unrelated to frequency or voltage, then we should have a separate standard that addresses this issue. The deliverable noted is a requirement for reporting all trips and abnormal reductions in active power. In our experience most "abnormal" reductions are prime mover related. If it was intended to only require reporting an abnormal reduction or trip during a system disturbance only, it is not clear that this deliverable is being met. We agree that generation outages due to frequency and voltage excursions should be tracked but the scope of the SAR goes well beyond that point. Why take a perfectly fine standard that addresses a known system issue and expand the scope into something that is not clearly defined. Consider expanding the scope of PRC-004 instead and include operations that affect the output of a BES Generation source and leave PRC-024-3 as a frequency and voltage ride through standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The Project 2021-04 Modifications to PRC-002 drafting team is in charge of monitoring efforts. The drafting team will coordinate with the PRC-002 team in the future pertaining to the necessary recording devices. The metrics will be forwarded to the drafting team for their consideration. This SAR team has modified this requirement and is now only applied to grid system events. The SAR has also been modified and expanded to include IBR AUX systems. Current cessation mode would be included under generation ride-through topic.	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No

Document Name	
Comment	
Xcel Energy supports the comments offered by EEI, NAGF, and MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see response to MRO.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

Southern Company does not agree due to the following concerns:

1. *A reporting requirement that all trips or reductions in power output are reported by the GO to the TOP, BA, and RC.*

Southern Company disagrees with this deliverable. **The RC, BA, and TOP should be responsible parties for determining the magnitude threshold and duration-of-time thresholds GO/GOP to report trips or reductions in power output.** This will ensure that the RC, BA & TOP are not burdened by notifications for trips/reductions that do not affect the Bulk Electrical System (BES) and ultimately take their attention away from matters of higher priority for ensuring the reliability of the BES. In addition, it is the belief of Southern Company that **the RC, BA & TOP already has the ability request information about trips or reductions in power output from the GO/GOP under the regulatory framework of NERC Reliability Standard IRO-010-4 and TOP-003-4.**

2. *A requirement that abnormal reductions in active power (i.e., tripping from protections or notable reductions from controls) are analyzed by the GO to develop a corrective action plan, if possible. Situations where corrective action plans are not able to be developed shall be reported to the TOP, BA, and RC.*

Southern Company disagrees with this deliverable. **Southern Company believes that the 'trip' portion of this deliverable is already an enforceable requirement under the regulatory framework of NERC Reliability Standard PRC-004-6.**

As written, *'notable reductions from controls'*, lacks the detail required to provide a standard drafting team (SDT) with proper direction to develop a requirement(s). **As this Standard Authorization Request (SAR) relates to dynamic ride-through performance of generators Southern Company requests that the SAR SDT add an example magnitude threshold and duration-of-time threshold for 'notable reductions from controls'.** Adding the additional information will prevent any developed requirement(s) from overreaching beyond the intention of this SAR. The communication of unit derates, where necessary for system operation, is likely already being communicated where specified by the RC/BA/TOP data specifications of IRO-010 and TOP-003.

3. *A clear requirement that momentary cessation, or temporary ceasing of current injection during BPS fault events, is deemed unacceptable performance for BES generating resources.* Inverter-based generating resources employing momentary cessation shall develop a corrective action to mitigate its use. Legacy facilities prior to the effective date of the standard should receive an exemption; however, resources with a commercial operation date after the effective date of the standard (and possibly the PRC-024-3 implementation date) shall be required to eliminate the use of momentary cessation within "ride through envelopes" (e.g., the existing PRC-024 "No Trip Zone").

The opening statement is contrary to real world expectations that the generation resource is not allowed to protect its equipment for BES system events. If this is the expectation, then the BES system should not be allowed to have fault events in the first place.

The implementation date for NERC Reliability Standard PRC-024-3 — Frequency and Voltage Protection Settings for Generating Resources (NERC PRC-024-3) is October 01, 2022. As stated by the SAR requestors:

• "The existing PRC-024-3 is an equipment settings standard focused solely on voltage and frequency protection. However, this standard is serving little to no value for ensuring BPS-connected inverter-based resources remain connected and supporting the BPS during grid disturbances."

• "The purpose of this SAR is to retire PRC-024-3 and replace it with a performance-based ride-through standard that ensures generators remain connected to the BPS during system disturbances."

• "Retire PRC-024-3, and create a new PRC standard or completely overhaul and replace the existing PRC-024 standard."

Based on these statements Southern Company believes all generators with a commercial operation date prior to the effective date of requirements to be developed based on this SAR should not have to comply or retrofit. It is clear that any requirements developed based on this SAR will be different from the requirements of NERC PRC-024-3 and therefore the generators that need to comply should be adjusted accordingly.

4. The premise that there have been notable concurrent tripping or performance from synchronous generating resources due to frequency and voltage protection settings being too sensitive is flawed. There have not been increasing trends of synchronous machine protection system misoperations to justify that premise. The application of a ride through standard for synchronous machine generating plants was fully investigated during the original drafting effort of PRC-024 between 2008-2014. The conclusion of the standard drafting team, after multiple drafts, extended comment and consideration of comments from industry, direct consultation with FERC by standard drafting team members resulted in the realization that the standard could go no further than to specify a regions for restricting the tripping of those generators by protective relays for voltage-time and frequency-time areas that would cause the units to not be tripped for the majority of system events where the voltage or frequency was not normal. Further attempts to apply a ride through requirement should be abandoned for synchronous machines to avoid wasting everyone's time by having to restate why it is not feasible for that generation type.

5. Further, there are limited modifications that can be made to the existing equipment to achieve the goal of 100% ride-thru ability to any grid disturbance. Simply passing a regulation specifying it must be done does not change the ability of the equipment to do so. The replacement of existing inverters is not feasible – the power ratings and voltage/current specifications of existing installed invertors do not match the inverters offered today. The collection system of a PV plant cannot be reconfigured economically once it is in place.

6. Any additional ride through requirements should only be applicable to equipment placed in service after changes are made to this standard which may require additional ride-thru capabilities for IBR plants. We suggest that the transmission interconnection agreements be the proper method to assure that newly connected IBR facilities are built to maximize their ride through capability.

7. The lack of a specific grid disturbance for which generating resources are to be required to ride-through is problematic. If specific disturbance characteristics are specified, the generating community might have a fighting chance to design systems to achieve the goals. The application of global "you must ride through all grid disturbance" requirements to existing equipment not designed to do so is ludicrous.

8. The SAR states that auxiliary systems and their protection systems are explicitly excluded. The sub-systems of a conventional synchronous machine generating station are essential for the normal plant operation. Without many of those sub-systems, the main generator cannot run. The sub-system may be essential to the mechanical operation of the turbine too. Any system disturbance that causes any of those sub-systems to not be available will immediately affect the turbine/generator ability to run. The controls of the generator and turbine are interlaced and interlinked with the sub-systems. They cannot be removed from affecting the entire unit

operation. In effect, they cannot be separated from the generator and the unit availability. During system disturbances where sustained grid low voltage occurs, those sub-systems may or may not experience trouble. During the initial PRC-024 development, the Luminant company reported that some low voltage contactors dropped out for low voltage conditions, and others did not. In subsequent grid low voltage disturbances, it was observed that different sets of contactors dropped out. The indefinite response of magnetically sealed in contactor behavior for low voltage conditions was one of the problems with any meaningful successful application of ride-through standards to those types of facilities.

9. The SAR indicates that the desire of the standard revision is to address all possible causes of tripping and power reductions. Addressing ALL POSSIBLE CAUSES is indefinite and unachievable. No failsafe system can be built to withstand all possible causes.

10. With regard to the SAR question on alternatives, for which the SAR drafters included this text:

NERC has evaluated industry progress toward adopting the recommendations outlined in NERC guidelines, white papers, its prior Alerts, and other industry efforts. NERC believes that a nationwide standard for consistent requirements for generating resource ride-through is necessary to immediately address generating resource ride-through during grid disturbances moving forward.

Southern Company has implemented all possible inverter setting changes included in the two NERC alerts on the Loss of Solar Resources. We note that several of our units have continued to react to major grid disturbances by ceasing to generate. The communication of the adjustment of the settings, and the limitations to adjustments we have discerned, have been communicated to the parties included in the NERC alert recommendations. It is for this reason we implore the SDT to look forward rather than backward with change requirements. The electric grid is not in immediate imminent danger due to this current condition. The requirement of maximizing IBR equipment connectivity and grid disturbance resolution support is best addressed through the transmission interconnection requirements rather than through reliability standards.

Likes 0	
Dislikes 0	

Response

Thank you for the comment.

1. The applicability of defining a threshold will be considered where applicable when drafting the standard in the performance criteria.

2. The team will look at PRC-004 and make sure there is no overlap, this SAR focusing on performance criteria IBRs. This will be reviewed during the standard drafting process when applicable.
3. Please refer to MRO comment.
4. Concerns about the applicability of the proposed standards to synchronous generators will be passed along to standard drafting team. The SAR has the option to create a new standard.
5. The exemption will be considered based on existing facilities capability and limitations.
6. The SAR includes this. The drafting team cannot support the ride-through requirement was solely covered by interconnection agreement.
7. The performance requirements for disturbances will be determined by the standard drafting team when applicable.
8. The team agrees with the comments and recognizes the difficulty including auxiliary systems in this standard.
9. The SAR has been redlined to limit to trips or power reduction in response to grid events.
10. The standard is focused on performance and acknowledges grid disturbances.

Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments

Answer	No
Document Name	

Comment

PG&E agrees with the comments provided by EEI that there have been performance issues with Solar PV Inverter Based Resources (IBRs) that need to be addressed, but as indicated by EEI, PG&E does not agree the replacement of PRC-024-3 is required to address those issues.

The current PRC-024-2 Requirements have worked well for synchronous generators, and it is expected that PRC-024-3 will improve the performance of those generators in maintaining the reliable operation of the Bulk Electric System (BES). As noted by EEI, there were losses of synchronous generator in some of the six disturbances noted in the SAR, but none of those appeared to be unexpected, unusual, or a result of non-compliance with the current PRC-024 Standard.

PG&E personnel responsible for PRC-024 believe trying to add an entire set of additional Requirements for IBRs on top of the current PRC-024 Requirements, or changing the Standard to be performance based for all generators would be extremely complex to implement and maintain, and would not improve the reliability for synchronous generators. PG&E recommends IBR performance should be covered under a new Standard specifically developed for the unique characteristics of IBRs.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see response to EEI.	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No
Document Name	
Comment	
MidAmerican supports MRO NSRF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see response to EEI.	
Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #1.	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see response to EEI.	
Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	

WEC Energy Group is voting no due to the following concerns:

- “Purpose or Goal” section calls for complete replacement of PRC-024-3 to ensure generators remain connected during disturbances, but the “Industry Need” section clearly identifies this issue applies to IBR only. Industry can agree that current standard as is, is very well effective for traditional synchronous generating resources, therefore WEC believes that standard does not need to be rewritten but rather modified to cover specific IBR issues. WEC believes that statement “… notable concurrent tripping or performance from synchronous generating resources…” is not well supported by data from recent disturbances.
- Proposed “performance based” term needs to be better defined within the SAR.
- If industry recommendation is to include other protective elements or control systems, then it should be done separately and new standards should be developed. Good examples are PRC-025 and PRC-026.
- Some of the “possible causes of tripping and power reductions” listed in SAR are load responsive in nature, therefore should be addressed within existing Standards that cover load-responsive requirements.
- “Detailed Description” section indicates that momentary cessation is deemed unacceptable. Did the SAR requester confirm with all equipment manufacturers that momentary cassation can completely be eliminated? There are still inverter manufacturers that produce equipment with momentary cessation in their design because of current limiting components. The SAR suggest a corrective action plan to be developed to mitigate the issue. What if issue cannot be mitigated?

Likes 0	
Dislikes 0	
Response	

Thank you for the comment. Concerns about the applicability of the proposed standards to synchronous generators will be passed along to standard drafting team. The SAR has the option to create a new standard. By "performance based" term this SAR extends the scope of NERC PRC-024-3 from a protective settings standard to defining performance requirements of BES generating resources remain connected and providing essential reliability services during grid disturbances, something stated within the project scope. The drafting team does not think any "possible causes of tripping and power reductions" listed in this SAR are load driven. It is focused on BES Generating Resources. PRC-025 and PRC-026 have been added to the SAR for future review. Momentary cessation of legacy units will also be considered by the standards drafting team.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AZPS agrees with the following comments that were submitted by EEI on behalf of its members: "The incidental operation of synchronous generators during some of the identified six NERC disturbance reports do not warrant the creation of a new ride through Reliability Standard replacing PRC-024-3 because the performance of most of the affected resources, outside of the solar PV resources, performed as designed and expected, and met the requirements of PRC-024-3. While there were losses of synchronous generators in some of the six disturbance reports cited in the proposed SAR, none appear to be unexpected, unusual or the result of non-compliance with PRC-024" "Additionally, if the intent of the SAR is to "create a comprehensive, performance-based ride-through standard," development of a standard would need to account for retirement of other relay setting standards such as PRC-025-2 and PRC-026-1, to prevent duplicative requirements and compliance obligations."	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment. Please see response to EEI.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports EEI's comments for this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see response to EEI.	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
In describing the scope, the SAR states *"The scope of the ride-through standard shall explicitly exclude auxiliary systems and their protection systems. Abnormal performance or unexpected tripping of these protections do not pose a systemic BES reliability risk. However, protections and controls directly focused on the generator and its prime mover (e.g., overspeed, power-load imbalance, overvoltage, phase jump, overcurrent) or plant-level (e.g., voltage, current, frequency, phase, etc.) have posed notable risks to BES reliability and should be addressed directly in this standard."* However, auxiliary systems that in turn unexpectedly trip an entire plant pose a risk to reliability. While these systems should not be explicitly modeled, the OP, BA and RC should be in a position to understand when a facility will trip. As an absolute minimum, this information should be required from facilities currently being planned and installed.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment. The updated SAR has resolved and addressed this comment.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

The NAGF provides the following comments for consideration:

1. The NAGF believes that there is little justification for retiring PRC-024-3 for synchronous generators and that any new standard should be focused on IBR performance issues. Note that GOs have invested tremendous effort and money in achieving compliance with the PRC standards and are achieving the desired enhancement of BES reliability. Replacing them with something substantially different would require significant expenditures with no identifiable benefit. Any new standard should address only gaps in existing standards, as opposed to tearing down and rebuilding them.

2. Project Scope Comments:

a) Second Bullet: "Creates a comprehensive, performance-based ride-through standard with the purpose of ensuring BES generating resources remain connected and providing essential reliability services during grid disturbances."

The NAGF recommends that other relay-setting PRC standards be considered for retirement/modification beyond PRC-024-3. For example, PRC-025-2, which has the purpose to assure that load responsive relays are set to prevent unnecessary tripping during system disturbances, and PRC-026-1, which has the purpose to ensure that load-responsive relays are expected to not trip in response to stable power swings during non-Fault conditions. The NAGF believes that if a truly comprehensive performance-based ride-through standard is created, then the regulatory burden of other relay setting PRC standards pertaining to how generator protection responds to grid disturbances should be reviewed and incorporated. It seems that a comprehensive generator ride-through standard would apply to not only 24, 27, and 59 functions (PRC-024-3) but would also include trips of generating resources in response to 21, 50, 51, 51VR, 51VC, 67 (PRC-025-2) and/or 21, 40, ,50, 51, 78 (PRC-026-1) function operations in response to grid disturbances.

3. Detailed Description of Project Deliverables Comments:

a) Bullet #3: “A reporting requirement that all trips or reductions in power output are reported by the GO to the TOP, BA, and RC.”

The NAGF believes that this statement is too vague or is stated imprecisely for this deliverable. Reductions in power will occur for a wide variety of reasons such as clouds passing over or the setting of the sun at a solar farm, a drop in wind speed, wet coal, changes in condenser circulating water temperature or discharge water temperature limits at a thermal plant, starting an additional large fan or pump, inlet air temperature changes to gas turbines, reduced water flow at a hydro plant – none of these causes of power reduction would have any relation to PRC requirements and no additional reporting other than that required by existing TOP requirements should be necessary. We believe this deliverable should be more focused, such as “A reporting requirement that all trips or reductions in power output in response to grid disturbances are reported by the GO to the TOP, BA, and RC.”

b) Bullet #4: “A requirement that abnormal reductions in active power (i.e., tripping from protections or notable reductions from controls) are analyzed by the GO to develop a corrective action plan, if possible. Situations where corrective action plans are not able to be developed shall be reported to the TOP, BA, and RC.”

The NAGF believes that such trip analysis and corrective actions are already addressed by PRC-004 and therefore this deliverable/requirement is redundant.

c) Bullet #5: “Legacy facilities prior to the effective date of the standard should receive an exemption; however, resources with a commercial operation date after the effective date of the standard (and possibly the PRC-024-3 implementation date) shall be required to eliminate the use of momentary cessation within “ride through envelopes” (e.g., the existing PRC-024 “No Trip Zone”).

The NAGF supports the exemption for legacy IBR facilities. The NAGF recommends that the performance-based standard include documented equipment limitation exemptions similar to PRC-024-3 R3 and these should apply to all generator types rather than just carving out an exemption for the application of momentary cessation on legacy IBRs existing prior to the effective date of the standard (and possible the PRC-024-3 implementation date). For example, if an existing turbine has frequency limitations that do not meet the requirements of the new ride-through standard, no corrective action plan should be necessary should the turbine trip in response to a frequency excursion outside of its capability. There appears to be nothing in the SAR that addresses limitations of existing equipment other than that of legacy IBRs applying momentary cessation.

d) Bullet #7: “A clear requirement that prolonged plant controller interactions that impede the ability of the resource to dynamically respond to the grid disturbance and preclude the ability to fully provide essential reliability services are deemed unacceptable and should be addressed by a corrective action plan.”

The NAGF is concerned with the potential ambiguity associated with this deliverable. This deliverable seems to be focused on eliminating some of the undesirable IBR performance issues, but the wording of this deliverable could be interpreted to apply to integrated plant or unit protection schemes that may indeed “impede the ability of the resource to dynamically respond to grid disturbances” but are designed to protect the boiler or nuclear reactor from pressure or level excursions, steam turbines from overspeed, operation at resonant frequencies or moisture intrusion, etc. Generator Owners should be able to protect their equipment from catastrophic damage without having to implement a corrective action plan should these protection or control features impede dynamic response to grid disturbances.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Concerns about the applicability of the proposed standards to synchronous generators will be passed along to standard drafting team. The SAR has the option to create a new standard. The team has considered the comments and modified the SAR to reflect these specified standards and any other applicable standards. The SAR has been modified to reflect the changes to 3A as suggested. Concerns regarding PRC-004 and PRC-024-3 legacy exemption retention will be passed along to the standard drafting team to be considered. 3D was reflected in redlines to SAR. This comment will be reviewed while drafting the standard.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2	
Answer	No
Document Name	
Comment	
On the bottom of page 2, the SAR states: “The scope of protections and controls involved in this ride-through standard shall include all generator protections and controls that affect the electrical output of the BES generating resource or plant. To be clear, the project should specify the protections and controls in scope of the ride-through performance and define the term ride-through, as necessary.” Will the scope include requirements that developers/GOs of any new interconnection projects be required to provide protection and control models to the TO or PC? The SRC recommends that the SDT indicate all “protection and control equipment, including auxiliary	

equipment” that will affect the ride-through capabilities of the generator during disturbances. The SDT should identify the auxiliary systems that the ride-through should not affect. On page 3, under Detailed Description, the SAR calls for “A requirement that abnormal reductions in active power (i.e., tripping from protections or notable reductions from controls) are analyzed by the GO to develop a corrective action plan, if possible. Situations where corrective action plans are not able to be developed shall be reported to the TOP, BA, and RC.” This description reads much broader than what is described in the SAR purpose. In the purpose it is directed specifically towards “fail to ride through system events”. Is the intent of the SAR scope to create a requirement to report reductions in active energy which go beyond “fail to ride through system events” and include abnormal reductions of any cause? The SRC requests the SAR DT clarify the project scope. On the bottom of page 3, the SAR states, “Legacy facilities prior to the effective date of the standard should receive an exemption; however, resources with a commercial operation date after the effective date of the standard.” We are concerned that there will be significant amounts of IBR facilities that will be exempt from these requirements. In addition, this seems to be at odds with the“all” language contained in the last bullet on the bottom of page 2 (and as mentioned in the SRC comments above). In 2018, a SAR was introduced and denied by the Standards Committee to correct momentary cessation of IBRs that had no such exemption because of the risks existing facilities were causing on the BES. This SAR does not propose any solutions to address that risk. We recognize that there are some IBR installations which pre-date the technology to meet the SAR purpose. However there are already numerous amounts of IBRs in operation which can adopt new technology to meet the SAR’s purpose. A blanket exemption should not be a part of the standards and instead some form of exemption process should be utilized. Further between the time this standard may be complete and the time it takes effect due to the need for regulatory approval, which may be over two years. Numerous additional new installation of IBRs would become grandfathered which certainly can meet the ride through requirements. The SRC recommends exemptions be limited to technical infeasibility.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. It will be considered when the standard is drafted. Models are not within the scope of this drafting team since this a performance standard. This question more refers to MOD-026 and MOD-027

The drafting team understands that the auxiliary systems are critical. However, considering that complexity of identifying the auxiliary equipment to be included in the standard, it has been decided not to include them in the scope. The team assumes that the equipment owner will take the necessary steps to make sure that the auxiliary systems will not trip unexpectedly to degrade the performance of the generation resources during systems events. The drafting team has discussed this point and will be discussing this more in-depth when drafting the standard.

The drafting team does not intend to create a requirement that goes beyond "riding through system events". The team agrees with your concern and modified the SAR accordingly to only be for grid-related disturbances.

The team shares your concern related to legacy equipment and modified the SAR to reflect the comment regarding legacy systems and exemptions.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

While EEI agrees in principal that that there have been performance issues, primarily with Solar PV Inverter Based Resources (IBRs), that need to be addressed, we do not support the retirement of PRC-024.

While there were losses of synchronous generators in some of the six disturbance reports cited in the proposed SAR, none appear to be unexpected, unusual or the result of non-compliance with PRC-024. As noted below, all of these six events linked within this SAR indicate solar PV performance problems, not synchronous generator problems.

Additionally, if the intent of the SAR is to "create a comprehensive, performance-based ride-through standard," development of a standard would need to account for retirement of other relay setting standards such as PRC-025-2 and PRC-026-1, to prevent duplicative requirements and compliance obligations.

For these reasons, we do not support the retirement of PRC-024-3. However, we offer an alternative approach in our response to question 2.

NERC 2021 California Disturbances Report (2022)

- June 24, 2021 – **Loss of 765MW of solar PV resources** (27 facilities) and 145MW of DERs (no synchronous resources lost).
- July 4, 2021 – **Loss of 605MW of solar PV resources** (33 facilities) and 46MW of DERs; 125MW; additionally, a single 125MW CT tripped due to two defective sensors as reported by the GO.
- July 28, 2021 – **Loss of 511MW of solar PV resources** (27 facilities) and 46MW of DERs (no synchronous resources lost).
- August 25, 2021 – **Loss of 583MW of solar PV resources** (30 facilities) and 212MW gas turbine tripped as a result of a correct operation of a RAS scheme. An additional gas turbine tripped during this event due to the failure of the excitation system (failed diodes). As stated in the report, the diodes were redundant but can only be detected during manual inspection. It is speculated that the redundant diodes failed as a result of the event, GO has indicated they will increase their inspections to avoid future failures.

NERC Odessa Disturbance Report (2021)

- May 9, 2021 Event – Initial fault occurred during CT startup testing when a surge arrester failed taking out one CT and causing another to run back for a total loss of 192MW. After this event **1112MW of solar PV output was lost**, in addition 36MW of output from 4 wind power plants.
- June 26, 2021 Event – Failed H-Frame structure causes the **loss of 518MW at 5 PV facilities**.

NERC San Fernando Disturbance Report (2020) July 7, 2020

- Static wire on a 230kV line failed causing the tripping of two lines on a double circuit tower. In addition, a nearby 230kV line relay mis operated. The result was the initial **loss of 205MW of solar PV output**. When trying to restore the lines, the second line tripped out causing the larger event, the **loss of 1000MW of solar PV output** (no synchronous resources lost).

NERC Palmdale Roost and Angeles Forest Disturbances Report (2019)

- April 20, 2018 (Angeles Forest) – A splice on a 500kV line failed causing a B-C phase fault which was cleared within 2.6 cycles. The fault caused the **loss of 860MW of solar PV output** in CAISO and 17MW in LADWP. In addition, a natural gas turbine tripped as a result of the fault. The report indicates the plan tripped on low fuel pressure causing the natural gas turbine to trip and the reduced output of a combined cycle steam generator to reduce output to 75MW for a total loss of 200MW. There was an additional loss of 130MW of DER output.
- May 11, 2018 (Palmdale Roost) – The disturbance was caused by a bird nest on a 500kV line that caused a line flashover (B phase to ground fault). As a result, there was a loss of **630MW of solar PV output in CAISO**, 48MW in LADWP and 33MW in IID. Additionally, there was 100MW of DER output lost (no indication of any synchronous generation lost during this event).

NERC Canyon 2 Fire Disturbance Report (2018)

- Canyon 2 Fire Disturbance, Oct. 9, 2017 – Two transmission lines faulted near Anaheim Hills, CA. The first fault occurred on a 220kV line at 12:12 PM and the second occurred at 12:14 PM on a 500kV line. The first fault resulted in the **reduction of 682MW of solar PV output**, which the second resulted in the **reduction of 937MW of solar PV output** (no indication that any synchronous generation was lost).

NERC Blue Cut Fire Disturbance Report (2017)

- On Aug. 16, 2016 AM the Blue Cut fire began in Cajon Pass, CA. As a result of the widespread fire SCE experience thirteen 500kV line faults and LADWP experienced two 287kV faults. Four of the fault events resulted in the **loss of 1,200MW of solar PV output** (no indication any synchronous generation was lost).

Likes 0	
Dislikes 0	

Response

Thank you for the comment. Concerns about the applicability of the proposed standards to synchronous generators will be passed along to standard drafting team. The SAR has the option to create a new standard. The team has considered the comments and modified the SAR to reflect these specified standards and any other applicable standards.

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

Ride-through is not a defined term in the NERC Glossary of Terms nor NPCC Glossary of Terms. The objective of the SAR is commendable, however the specific characteristics of the disturbances addressed by the new standard needs to be carefully defined. Usually the magnitude and duration of grid disturbances should be defined. Particular contingencies should be specified and studied to ensure those applicable reasonable foreseeable disturbances can be assessed and addressed.

Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The existing SAR allows the standard drafting team to develop a term for the NERC Glossary to include the definition of "ride-through" as well as other relevant terms that might be used in the standard. The drafting team also agrees that specification of disturbance characteristics (e.g., type of fault, duration, voltage class, etc.) will be a critical part of the ride-through standard drafting process.	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

Regarding the 4th bullet in the "Project Scope" section, ERCOT believes the SAR should not exclude auxiliary systems that could impact the facility's continued operation. The SDT should review the various types of auxiliary systems in use at in-scope facilities and determine whether to exclude any of them. ERCOT suggests revising the 4th bullet as follows:

This standard should address protections and controls directly focused on the generator and its prime mover (e.g., overspeed, power-load imbalance, overvoltage, phase jump, overcurrent) or at the plant level (e.g., voltage, current, frequency, phase, etc.) because they pose notable risks to BES reliability. The SDT will determine whether this ride-through standard may exclude auxiliary systems that do not impact the facility's ability to maintain real and reactive power during a disturbance.

Regarding the 2nd sub-bullet in the "Detailed Description" section, ERCOT suggests the standard contain a requirement for a GO to report only trips or reductions in real power or improper reactive power response (trips or reductions within some threshold of the performance parameters established in the standard).

Regarding the 3rd sub-bullet in the "Detailed Description" section, ERCOT suggests clarifying the term "abnormal" to include trips and reductions in real power or improper reactive power response failing to meet the performance parameters established in the standard. Further, ERCOT suggests the SDT include a requirement for the GO to develop *and implement* a corrective action plan (CAP) or report to its TOP, BA and RC any CAP it cannot implement *due to technical infeasibility*. Finally, ERCOT suggests removing "if possible" because ERCOT's proposed language (above) addresses situations where the GO cannot implement the CAP due to technical infeasibility.

Accordingly, ERCOT suggests modifying the 2nd and 3rd sub-bullets as follows: • The proposed deliverable is a new NERC standard (or significant overhaul and revision of PRC-024-3) that includes the following key elements: • ... • A requirement for a GO to report to its TOP, BA and RC trips or reductions in real power or improper reactive power response (i.e., trips or reductions within a threshold of the performance parameters established in the standard). • A requirement for a GO to: (a) analyze abnormal trips or reductions in real power or improper reactive power response (i.e., tripping from protections, notable reductions from controls, trips or reductions in real power or improper reactive power response failing to meet performance standards established in this standard); and (b) develop and implement a corrective action plan (CAP). If a GO cannot implement a CAP because it is not technical feasible to do so, the GO must report that fact to its TOP, BA, and RC. • ... Regarding the 4th sub-bullet in the “Detailed Description” section, ERCOT agrees with the SRC that the project should not exempt legacy facilities. Exempting legacy facilities will not address the reliability-related need this project addresses.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments. The Auxiliary Systems concern has been addressed in the redlined SAR. The SAR has been modified to address reporting concerns. Thresholds may be addressed by the drafting team. Legacy systems should only be exempt if, after engineering analysis, corrective action is not possible or practical (need to define practical). The language was modified to reflect the changes regarding implementation of a Corrective Action Plan and removed "if possible".	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No

Document Name	
Comment	
Please address and clearly explain the relationship between the two SARs ("Revision of relevant Reliability Standards to include applicability of transmission-connected dynamic reactive resources" approved in April, and "Generator Ride-Through Standard (PRC-024-3 Replacement)". Failure to provide this clarification will result in confusion between intents and requirements for different types of devices and may not clearly align with the earlier whitepapers and recommendations. Additionally-please clarify that Synchronous Condensers, STATCOMs, SVCs and HVDC are not considered generator protection and control systems and should not be included in this standard. If Synchronous Condensers, STATCOMs, SVCs and HVDC are intended to be included in the standard, it needs to be revised to reflect that and include proper terminology, consideration of capability, and requirements specific to transmission-connected dynamic reactive power resources as opposed to generation resources.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The team has had an additional SAR added to the project to cover the Generation Ride-through. The original SAR will be included with the Ride-through SAR for the team to use when drafting the standard(s) for this project. Each of the two SARs will be used when addressing their respective aspects of this project. Devices that are only reactive devices are not included in the current SAR. This comment pertains to the first SAR of this project and not the current SAR.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy supports EEI's comments.	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see response to EEI.	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
Ameren agrees with EEI's comments. A new ride through standard should be created for IBR's only. The performance issues were with IBR's not synchronous generators.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see response to EEI.	
LaKenya VanNorman - Florida Municipal Power Agency - 3,4,5,6 - SERC, Group Name Florida Municipal Power Agency (FMPA)	
Answer	No
Document Name	
Comment	
Florida Municipal Power Agency (FMPA) supports comments submitted by NAGF.	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment. Please see response to NAGF.	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
At this point, it is hard to disagree with this project since it is still broad and vague	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA supports revision of the current PRC-024-3 rather than creation of a new reliability standard. BPA believes the project will raise the bar on protection of BPS-connected inverter-based resources.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes

Document Name	
Comment	
Texas RE agrees with the need for this project to develop a comprehensive generator "ride-through" standard in lieu of the current PRC-024's focus solely on voltage and frequency protection settings. As the September 2021 Joint Odessa Disturbance Report for Texas Events on May 9, 2021 and June 26, 2021 ("Odessa Disturbance Report") highlighted, "the systematic nature of [Inverter-Based Resource tripping or cessation] events across multiple interconnections and a wide range of facilities, many of which are recently energized, warrants significant enhancements to the NERC Reliability Standards to address gaps in BES inverter-based resources." (Odessa Disturbance Report, at 29). These recommendations included the need for developing a new generator protection and control ride-through standard to replace the current PRC-024-3 to address continued examples of widespread tripping that are not addressed by the current PRC-024-3 requirements. Texas RE appreciates that the SAR provides an approach to capture the range of performance issues (PLL loss of synchronism, subcycle ac overvoltage protection, dc reverse current, and wind converter crowbar failures) that have resulted in widespread tripping incidents across a number of interconnections, including the ERCOT Interconnection. It further recommended that NERC do so on an expedited timeframe. Texas RE notes that this call of expedited action is even more pressing given the recent tripping of significant inverter-based resources in the ERCOT Interconnection earlier this year, continuing a pattern of generator performance issues in this area. NERC has highlighted grid transformation issues as the single greatest risk to grid reliability at the current time. Texas RE appreciates the SDT's important role, care, and commitment to addressing these performance issues in this project.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment and the timeline input recommendation.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	

The NPCC Regional Standards Committee agrees with the proposed scope as described in the SAR.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
The Project 2020-02 webpage reflects that the initial project SAR, posted for industry comments on 3/30/2020, was revised and subsequently accepted by the NERC Standards Committee on 4/20/2022. A redline of the SAR accepted by the Standards Committee in April 2022 vs. the initial SAR posted in March 2020 is posted on the project page. It appears that a different Project 2020-02 SAR (prepared by NERC executives and staff) was presented to and accepted by the NERC Standards Committee a month later, on	

5/18/2022. We suggest that a redline of the SAR accepted by the Standards Committee in May 2022 vs. the SAR accepted by the Standards Committee in April 2022 (or the initial SAR posted in March 2020) be added to the project page. It is not clear why the SAR submitted by the Chair of the System Analysis & Modeling Subcommittee and accepted by the Standards Committee in April 2022 was "abandoned" a month later to be replaced by the SAR submitted by NERC.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment and support. The team will proceed with the two SARs assigned by the SC and will be considered when drafting the standards.	
Nazra Gladu - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for the response.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Isidoro Behar - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	

2. *Provide any additional comments for the drafting team to consider, if desired*.	
LaKenya VanNorman - Florida Municipal Power Agency - 3,4,5,6 - SERC, Group Name Florida Municipal Power Agency (FMPA)	
Answer	
Document Name	
Comment	
Florida Municipal Power Agency (FMPA) supports comments submitted by NAGF.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see response to NAGF.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	
Document Name	
Comment	
While FirstEnergy does agree that an assessment needs to be conducted to ensure reliability of the BES due to the changing mix of generating resources, we do not agree that a reliability standard should result in additional penalties for a GO if generating capacity requirements are not met due to a fuel shortage caused by unforeseen events. FirstEnergy generators already participate in the PJM capacity market and are required to provide generating capacity based on summer ICAP testing results. A generator is assessed financial penalties by PJM if it cannot meet its generating capacity requirements and therefore, we caution against a double jeopardy situation. We also suggest the RC and BA, not the GO, should be responsible for developing a CAP if generation capacity demands are not met during periods of constrained resources. It is the responsibility of the Transmission Grid Operator (e.g., PJM), not the GO, to ensure that adequate generating resources are available during periods of constrained resources. Operating characteristics of IRBs are the cause of	

constrained resources and mitigation actions over-and-above PJM generating capacity requirements should not be placed on fossil generation resources.

Further, FirstEnergy supports EEI's comments, which states:

As an alternative to the proposed PRC-024 SAR, EEI suggests that a new SAR be developed to address performance issues specifically affecting IBRs. This new SAR could leverage key scope items from this proposed SAR to create a new performance- based NERC Reliability Standard that is focused on IBRs. As a suggested scope, we propose modifying this SAR as follows:

-- Trips or reductions in active power that occur because the IBR does not operate as expected (excludes cloud cover, setting sun, etc.), but not associated with protection system trips, (PRC-004 already addresses protection system tripping) are to be analyzed by the GO to develop a corrective action plan. Situations where an issue cannot be corrected, the GO shall develop a report detailing the limitations of the IBR and provide it to the responsible TOP, BA, and RC.

-- Momentary cessation, or temporary ceasing of current injection in response to grid disturbances, is deemed unacceptable for BES generating resources. Inverter-based generating resources employing momentary cessation shall develop a corrective action to mitigate its use unless the issue cannot be corrected. Legacy facilities prior to the effective date of the standard should receive an exemption; however, resources with a commercial operation date after the effective date of the standard shall be required to eliminate the use of momentary cessation during system transient disturbances where the system voltage or frequency falls within the "No Trip Zone" provided in PRC-024-3, which is subject to enforcement October 1, 2022.

-- Include the development of new terms to address terms specific to IBRs or where commonly used industry terms have created some confusion for IBR owners. E.g., No Trip Zone, trip, momentary cessation, and any other relevant terms that may require clarification within the NERC Glossary of Terms.

-- Prolonged IBR controller interactions that impede the ability of the resource to respond dynamically to the grid disturbance and preclude the ability to provide essential reliability services are deemed unacceptable and should be addressed by a corrective action plan. In situation where the GO has determined the issue cannot be corrected, a report shall be developed detailing the IBR limitation and provide it to the responsible TOP, BA and RC.

--If the TOP, BA, or RC inform the GO/IBR owner of a tripping occurrence, cessation event, or IBR controller interactions that are not reported or otherwise identified by the GO/IBR Owner, the responsible GO shall be responsible for analyzing

the facility's performance during the event, developing a corrective action plan, and making this available to the TOP, BA, and RC or in the situation where the issue cannot be corrected, informing the TOP, BA and RC.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The team has redlined to the SAR to only include systems disturbance or system electrical events. Please also see response to EEI.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	

The current PRC-024-2, "No Trip Zone" is very clear and easy to understand for frequency and voltage parameters. The SAR Requesters' logic and SAR details appear to be pretty thorough, with the exception of replacing the "No Trip Zone" with "fault ride-through capabilities" as proposed in the revised SAR (dated 4/28/2022). We recommend the SAR Requesters/SAR Drafting Team expand on the proposal to eliminate "No Trip Zone" requirements, and expand the discussion regarding the replacement "fault ride-through capabilities".

The revised SAR language seems to suggest that synchronous generating resources suffer from mis-trips and mis-application of the standard due to deficiencies identified in PRC-024-3 to the same degree that inverter-based resources do. None of the six disturbance reports cited as technical justification for the SAR reference loss of synchronous generation caused by an inadequate or missing requirement within PRC-024-3. From a reliability perspective, while GO/GOPs of IBRs stand to benefit from a replacement/overhaul of PRC-024-3, there is no clear benefit to GO/GOPs of traditional synchronous generating resources. We recommend that the SAR language be revised to clearly delineate the current issues with synchronous generation resources and the current issues with IBRs driving this proposed standard modification, and how the changes are impacting each technology.

The proposed scope explicitly excludes auxiliary systems with the rationale that "abnormal performance or unexpected tripping of these protections do not pose a systemic BES reliability risk" (Page 3, "Project Scope", 4th bullet point). Components of auxiliary systems like unit auxiliary transformers (UATs) typically feature protection that are capable of taking a generator offline. Given this, there may be a

heightened reliability risk if auxiliary equipment are not subject to the same requirements of the proposed standard as generator protection and controls. Auxiliary transformers (and BES GSUs) were added to the applicable equipment scope in the revision from PRC-024-2 to PRC-024-3, so an explanation is requested for why this inclusion is not being preserved.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The team has added the language for IBR aux systems and excluded traditional generation.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
Please clarify momentary cessation of "current injection during BPS fault events." Re: this SAR please explain if current injection refers to active current, reactive current or both?	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see response to EEI.	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT provides the following additional comments:	

The SAR specifically identifies protections/controls posing risks to BES reliability. The proposed standard should not specify criteria for every potential quantity that may trigger a trip. Specifying voltage and frequency envelopes should suffice. Operating within those envelopes should not trigger any other plant control or protection to trip. Not having high-resolution data limits the ability to identify the root cause of the events referenced in the SAR. High-resolution data, including data from phasor measurement units (PMUs), digital fault recorders (DFRs), and inverter-based oscillography, is critical to identify the root cause of disturbance events and, as such, necessary to develop a CAP. Additionally, high resolution data allows a better understanding of the interaction between local wind turbine ride-through control versus the facility plant controller. ERCOT believes this SAR should require data recording relating to voltage ride through and to add appropriate language to PRC-002-2. Finally, ERCOT suggests the SDT consider IEEE 2800 when drafting a proposed standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The team has redlined the SAR to reflect these changes regarding data recording.	
Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	
Document Name	
Comment	
In place of GOs only notifying the PC and TP when they can’t meet the ride-through requirement or upon request, GOs should be required to periodically (annually?) provide, or confirm no changes to, their generator protection trip settings to the PC and TP.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. This will be passed to the standard drafting team for consideration.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	

Answer	
Document Name	
Comment	

If an attempt is made to define the ride through then it should consider the Bulk Electrical System (BES) as well as all the applicable/foreseeable generating resources that can potentially impact the BES.

A suggestion is made to use, consistently, just the Bulk Electrical System (BES) acronym and not to loosely interchange with BPS whose meaning is different than BES in the NPCC region (Bulk Power System as determined by Directory #1/A#10 methodology)

The SAR mentions that "Generator ride-through is a foundational essential reliability service.". To date the "ride-through" is not defined as a reliability service the same way we understand the following:

- **Frequency support** - provided through the combined interactions of synchronous inertia and frequency response, as services to arrest the decline in frequency and eventually return the frequency to the desired level
- **Ramping and Balancing** – provided through dispatch by the generating units with active power management capability and ability to respond to dispatch signals
- **Voltage Support** - provided through planning and confirmation testing of reactive power sufficiency per unique characteristics of their respective BA systems.

Having generating resources with ride-through capabilities are not a guarantee that the generating units will remain connected to the grid even less of a guarantee they will provide BES support (reliability services during BES disturbance) since BES support is also a:

- Function of static and dynamic reactive power reserve capabilities to regulate voltage at those respective points in the system
- Function of levels of conventional synchronous inertia for respective balancing area/interconnection, and initial frequency deviation following the largest contingency event for the interconnection

This SAR should only be applicable to the protection/protective functions that trip the protected equipment in response to a BES disturbance, where the disturbance conditions do not pose a risk of damage to the associated equipment, whose protection must be prioritized (similar with PRC-025-2).

Equipment protection does not amount nor have a simultaneous compounded effect on grid reliability.

The SAR statement related to the cost impact associated to this Project being expected to be minimal, should not be treated as an accurate statement as long as the entire scope of the project has not even been identified.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The team has redlined the SAR to reflect possible new costs. NERC has been specific when designating the terms BES vs BPS in the SAR, these will remain distinct and not all BES. The drafting team will determine specific ride-through requirements. This comment will be passed along to the standard drafting team.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

As an alternative to the proposed PRC-024 SAR, EEI suggests that a new SAR be developed to address performance issues specifically affecting IBRs. This new SAR could leverage key scope items from this proposed SAR to create a new performance- based NERC Reliability Standard that is focused on IBRs. As a suggested scope, we propose modifying this SAR as follows:

- Trips or reductions in active power that occur because the IBR does not operate as expected (excludes cloud cover, setting sun, etc.), but not associated with protection system trips, (PRC-004 already addresses protection system tripping) are to be analyzed by the GO to develop a corrective action plan. Situations where an issue cannot be corrected, the GO shall develop a report detailing the limitations of the IBR and provide it to the responsible TOP, BA, and RC.
- Momentary cessation, or temporary ceasing of current injection in response to grid disturbances, is deemed unacceptable for BES generating resources. Inverter-based generating resources employing momentary cessation shall develop a corrective action to mitigate its use unless the issue cannot be corrected. Legacy facilities prior to the effective date of the standard should receive an exemption; however, resources with a commercial operation date after the effective date of the standard shall be required to eliminate the use of momentary cessation during system transient disturbances where the system voltage or frequency falls within the “No Trip Zone” provided in PRC-024-3, which is subject to enforcement October 1, 2022.

- Include the development of new terms to address terms specific to IBRs or where commonly used industry terms have created some confusion for IBR owners. E.g., No Trip Zone, trip, momentary cessation, and any other relevant terms that may require clarification within the NERC Glossary of Terms.
- Prolonged IBR controller interactions that impede the ability of the resource to respond dynamically to the grid disturbance and preclude the ability to provide essential reliability services are deemed unacceptable and should be addressed by a corrective action plan. In situation where the GO has determined the issue cannot be corrected, a report shall be developed detailing the IBR limitation and provide it to the responsible TOP, BA and RC.
- If the TOP, BA, or RC inform the GO/IBR owner of a tripping occurrence, cessation event, or IBR controller interactions that are not reported or otherwise identified by the GO/IBR Owner, the responsible GO shall be responsible for analyzing the facility's performance during the event, developing a corrective action plan, and making this available to the TOP, BA, and RC or in the situation where the issue cannot be corrected, informing the TOP, BA and RC.

Likes 0	
Dislikes 0	

Response

Thank you for the comment.
The standard drafting team will take into consideration that IBR ride-through performance is the chief motivation behind the present PRC-024 SAR.

The points applicable to generation ride-through will be considered in the context of a revised or new generation ride-through standard. Momentary cessation is an aspect of ride-through performance. The final standard may not be specific to causes of unsatisfactory ride-through but only describe the system conditions and/or events during which generation must ride-through and what constitutes satisfactory ride-through performance. Exemptions for legacy generation and possibly other factors for which exemptions should be permitted will be considered. The team has redlined the SAR to address these concerns. The fourth point regarding interactions that affect reliability services in general may go beyond the scope of disturbance ride-through which the SAR is limited to. The SAR has been redlined to make it more specific, when the team starts to draft the standard this will be noted and considered.

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2

Answer	
Document Name	

Comment

The current PRC-024 standard was written with conventional (rotating) generators in mind. Conventional generators are quite sensitive to generator speed (frequency) and abnormal speeds can damage, i.e. lower the life of, turbine blades. Hence the further away the frequency deviates from 60 Hz, the shorter the duration allowed for "no-trip." In contrast, Inverter-Based Resources (IBRs) don't have rotating parts whose speed is tied to their connection to the grid. Since IBRs are not affected by deviations in system frequency as much as conventional (rotating) generators, the SRC requests the PRC-024 SAR be revised to include a recognition for this difference as there may be different ride-through requirements for IBRs than conventional generators within the same interconnection. In addition, to aid in industry implementation, the SRC requests the SAR include the requirement to provide some real-world examples; e.g. in Technical Rationale, to illustrate how proposed standard requirements will ensure both IBRs and conventional generators are able to ride-through faults and how, had they been in place, would have addressed past issues of inadequate ride-through capability. Finally, the SRC requests that the SAR ask to expand the requirement in selecting a Standards Drafting Team (SDT) that is stated in Question 5 on the SAR form. The SRC agrees it is important to include entities that the standard will apply to, but in addition, entities who have a need for the information or bear responsibility to reliably operate within the bounds of the standard (even if the standard does not directly apply to them from a requirement and compliance standpoint), should also be included. The requirements set in any standard are intended to ensure the reliability of the BES as a whole which all registered entity functions have an impact or interest in. This should apply to any and all SARs and the SRC would like to ask NERC to address a change in the SAR form in the future.	
Likes 0	
Dislikes 0	
Response	
Thank you. Your comments will be considered during the drafting of the standard. The team will review and provide real world examples if available/applicable.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	

The NAGF notes that the SAR references the term Bulk Power System (BPS) and Bulk Electric System (BES) through the SAR document. Recommend consistent use of the terms in the Purpose, Project Scope, and Deliverables sections. In addition, the NAGF notes that the SAR is not consistent with regard to retiring and replacing PRC-024-3 (Purpose or Goal Section, first sentence). Bullet #1 of the Project Scope states “Retire PRC-024-3, and create a new PRC standard or completely overhaul and replace the existing PRC-024 standard.” Bullet #1 of the Detailed Description of the Project Deliverables states “The proposed deliverable is a new NERC standard (or significant overhaul and revision of PRC-024-3) that includes…).	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The team will make sure to use terms consistently moving forward. These terms are consistent, the scope allows these actions. The Purpose and Scope both articulate the retirement of the current PRC-024-3 and replacing it with a new or modified version.	
John Pearson - ISO New England, Inc. - 2	
Answer	
Document Name	
Comment	
Below are proposed changes for the “proposed deliverable” section of the SAR. *The proposed deliverable is a new NERC standard (or significant overhaul and revision of PRC-024-3) that includes the following key elements:* *A performance-based approach to generator ride-through rather than an equipment settings standard. The new standard shall include requirements that BES resources shall ride through grid disturbances and include quantitative measures (see below) on expectations for ride-through that address all possible causes of tripping and power reductions from BES generating resources (particularly generator, turbine, inverter, and all plant-level protection and controls, including auxiliary systems).*	

A reporting requirement that all trips or abnormal reductions in power output are reported by the GO to the TOP, BA, and RC. *A requirement that abnormal reductions in active power (i.e., tripping from protections or notable reductions from controls) are analyzed by the GO and shall be reported to the TOP, BA, and RC.*	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. These concerns have been addressed in the redlined SAR.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
Minnesota Power supports EEI’s comments for this question.	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see response to EEI (question 2).	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	
Document Name	
Comment	
AZPS suggests PRC-024 should remain unchanged as it applies to synchronous generators and that a new SAR be developed to address performance issues specifically affecting IBR's that are interconnected to the BES.	
Likes 0	
Dislikes 0	
Response	
The standard drafting team will take into consideration that IBR ride-through performance is the chief motivation behind the present PRC-024 SAR.	
Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #2.	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment. Please see response to EEI (question 2).	
Isidoro Behar - Long Island Power Authority - 1	
Answer	
Document Name	
Comment	
The stated purpose of this SAR is to retire PRC-024-3 and replace it with a performance-based ride-through standard that ensures generators remain connected to the BPS during system disturbances. Additionally, the SAR will focus on the generator protection and control systems that can result in the reduction or disconnection of generating resources during these events. As part of the development of the performance based standard or overhaul of PRC-024-3, it is recommended that the standard drafting team include and highlight specific references to the relevant IEEE Standard P2800-2022 clauses and to relevant FERC Orders (related to ride-through), where applicable. It will be important for stakeholders to discern similarities and differences between the new or revamped standard and these existing references. We can offer another comment, related to PRC-024-3, for consideration in the development of a performance based standard or overhaul of PRC-024-3. For PRC-024-3 applicability section 4.1.2, it mentions that it is for Transmission Owners in the Quebec Interconnection only. There are Transmission Owners outside the Quebec Interconnection that own BES generator step-up transformers (GSUs). Is PRC-024-3 intended to be applicable to Transmission Owners that own BES GSUs that are outside the Quebec Interconnection? If so, perhaps the “in the Quebec Interconnection only” should be removed from applicability section 4.1.2 in the next revision.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. This will be passed along to the drafting team along with consideration to IEEE-2800-2022 when drafting the standard.	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	

Answer	
Document Name	
Comment	
MidAmerican supports MRO NSRF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see response to EEI (comment 2).	
Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PG&E agrees with the comments and suggested scope provided by EEI; a new SAR should be developed to address the unique performance characteristics of IBRs.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see response to EEI (question 2).	
Anna Todd - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	
Document Name	
Comment	

N/A	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	

Southern Company disagrees with the "Cost Impact Assessment". We feel that generation resources will need to install high speed recorders to capture data on electrical events that occur and the reaction of generation resources to said electrical event. These high speed recorders will be essential for any requirement for analysis and development of corrective action plans. Southern Company purports that it will be costly to engineer, procure and install this equipment.

Noting that IBR components capable of providing the performance characteristics are just now beginning to be developed and offered by vendors coupled with regulatory requirements for providing that performance will certainly cause equipment suppliers to increase costs to the users.

With the cause of the concern raised in this SAR being the system disturbance, perhaps a more beneficial result can be achieved by investigating the causes of the system disturbances that have been resulting in natural responses of the IBR and synchronous machine based generating stations. Our experience has been that most of the existing IBR systems that operate perfectly given a network with no disturbances.

The recent development and adoption of IEEE P2800 (Standard for Interconnection and Interoperability of Inverter-Based Resources Interconnecting with Associated Transmission Electric Power Systems) is nowhere to be found in the SAR as a resource. It is Southern Company's opinion that IEEE P2800 be fully understood and used by the SDT as a resource of what operational capability limits exist for IBRs. P2800 goes into many of the aspects that IBRs face from a performance perspective. A common issue with IBRs is loss of synchronism because of the voltage phase angle jump that can occur with system disturbances. A voltage phase angle shift jump can

occur with the voltage magnitudes still within the no-trip zone, leading to momentary cessation because of loss synchronism of the IBRs synchronizing phase-locked loop control function. The Functional Entities identified in the PRC-024 standard have no control what-so-ever of the design and performance characteristics of the Inverter Based Resource manufacturers equipment. This leads to GOs attempting to coerce the IBR manufactures after-the-fact to change equipment settings and parameters to comply with operational situations that they are either not designed to perform to or, due to the technical nature of the IBR generation process, cannot perform to. To move to a performance based standard and holding the GO accountable for the design performance of the IBRs is futile at best. The only performance criteria defined in the SAR so far is impossible for all situations, and that is "A clear requirement that momentary cessation, or temporary ceasing of current injection during BPS fault events, is deemed unacceptable performance for BES generating resources".	
Likes 0	
Dislikes 0	
Response	
Thank you for comment. The SAR has been redlined to reflect the additional cost of high speed data recording devices, if or when required.	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	
Document Name	
Comment	
Xcel Energy supports the comments offered by EEI, NAGF, and MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see responses to the respective entities (question 2).	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO	

Answer	
Document Name	
Comment	

The MRO NSRF disagrees with the "Cost Impact Assessment". The MRO NSRF feels that generation resources will need to install high speed recorders to capture data on electrical events that occur and the reaction of generation resources to said electrical event. These high speed recorders will be essential for any requirement for analysis and development of corrective action plans. The MRO NSRF believes it will be costly to engineer, procure and install this equipment.

The MRO NSRF recommends replacing all instances of bulk power system (BPS) with Bulk Electrical System (BES) to ensure proper scoping of the SAR.

Likes 0	
Dislikes 0	

Response

Thank you for the response. The team has redlined and modified the SAR to address the concern.

The team checked with NERC SAR authors to reconfirm the distinct differences between terms is intentional and it will be left as-is.

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	
Comment	

Momentary Cessation Requirements for Existing Generators

While Texas RE appreciates the proposed SAR's focus on generator performance issues in general and momentary cessation issues in particular, Texas RE is concerned that the current proposed SAR would exempt facilities in commercial operation prior to the effective date of the new PRC-024-3 requirements from "the use of momentary cessation within 'ride through envelopes' (e.g., the existing PRC-024 "No Trip Zone"). (PRC-024 Standard Authorization Request, at 3-4). The Odessa Disturbance Report observed that momentary cessation issues resulted in generation loss, along with tripping issues inside of facilities during the event (Odessa Disturbance Report, at 7). In particular, the Odessa Disturbance Report noted: "legacy inverter momentary cessation setting with plant-level controller interactions prohibited quick active power recovery." (Odessa Disturbance Report, at 33). The report also noted other forms of momentary cessation issues, including settings that produced fixed reactive power injection with "no ability to control voltage post-contingency." (Odessa Disturbance Report, at 20). It further noted that "[t]his type of behavior was not known by ERCOT prior to the event analysis nor is this type of behavior supporting the BPS post-fault." (Id.).

Given the significance of these momentary cessation issues during the Odessa Disturbance event and other events over the past six years, Texas RE encourages the SDT to not limit momentary cessation performance requirements exclusively to new generation facilities. While Texas RE expects the SDT to move expeditiously with this project, Texas RE notes that the final revised standard may not be effective for several years. As a result, not only would existing generators not be covered by any momentary cessation requirements, but a number of planned generation resources would be similarly exempt. Given the growing role of inverter-based resources in the ERCOT Interconnection and others, this could result in a significant reliability gap.

Texas RE notes that momentary cessation issues are currently documented in NERC Reliability Guidelines (E.g., Reliability Guideline: BPS-Connected Inverter-Based Resource Performance (Sept. 2018) (2018 IBR Performance Guidelines). These existing guidelines note that "Existing and newly interconnecting inverter-based resources should eliminate the use of momentary cessation to the greatest possible extent." (2018 IBR Performance Guidelines, at 11). It is also important to note that one of the key findings in the Odessa Disturbance Report is that while these reliability guidelines are widely viewed and shared, entities are "not comprehensively adopting the recommendation(s) contained in those materials." (Odessa Disturbance Report, at vi). In short, a new Reliability Standard is required.

Texas RE acknowledges it may take time to review and implement settings to avoid certain momentary cessation-type performance issues. As the 2018 IBR Performance Guidelines note, however: "Existing resources may have hardware and/or software limitations based on a design philosophy using momentary cessation, and it may not be feasible to eliminate its use. For equipment limitations that cannot be addressed, PRC-024-2 Requirement R3.1 states that '[t]he [GO] 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.'" (2018 IBR Performance Guidelines, at 11-2). The drafting team could consider approaches that permit legacy systems lacking functionality to avoid momentary cessation issues to document those limitations for any new momentary cessation requirements developed in this project in a manner similar to the process currently provided in the existing PRC-024-3 Requirement R3.1.

Enhanced Communication Requirements

In addition to considering the incorporation of momentary cessation and other performance notification requirements as appropriate, Texas RE recommends the drafting team consider creating a new requirement for the GO to notify the GOP, in addition to the TOP, BA, and RC, regarding abnormal tripping. Since COM-001 and COM-002 do not include GO communications, an additional requirement for the GO to notify the GOP would be helpful for the GOP to have the information to communicate any GO issues via COM-001 and COM-002.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see response to EEI (comment 2).	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
Although PRC-024-3 is not applicable to BPA by registration, the PRC-024-3 Requirements R3 and R4 do impact BPA as a Transmission Planner and Planning Coordinator and will have substantial impact to BPA's interconnection requirements. BPA encourages the drafting team to address the inconsistencies in format of how TPs and PCs receive the data. Data consistency will support more efficient and effective modeling of relay settings	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The team will pass this on to the standard drafting team for consideration.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	

Comment	
No additional comments. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Alison Mackellar - Constellation - 5,6	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	
Document Name	
Comment	
N/A	
Likes 0	

Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
All protection and control system functions that will be in scope should be specifically listed in the standard. Guidance on complying with ride-through requirements should be provided by including detailed examples. A sufficient phase-in period should be part of the implementation plan to allow GOs time to achieve the additional coordination that will be required. Based on the defined project scope the new standard will enforce that unexpected trips, abnormal trips and reductions in power are reported to the pertinent entities. The term reduction of power needs to be defined since it is open for interpretation. Furthermore, this reporting-out could infringe on current standards like PRC-004.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. This will be passed along to the standard drafting team.	
Brian Lindsey - Entergy - 1,3,6	
Answer	
Document Name	
Comment	
The Cost Impact Assessment states incremental cost impact which is not correct. Additional analyses and design changes are likely based on the widespread loss of generating resources observed.	

Likes 0	
Dislikes 0	

Response
Thank you for comment. The SAR has been redlined to reflect the additional cost of high speed data recording devices, if or when required.

End of Report

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Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the [NERC Help Desk](). Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Generator Ride-Through Standard (PRC-024-3 Replacement)		
Date Submitted:	April 28, 2022 (revised March 31, 2023)		
SAR Requester			
Name:	Mark Lauby, Senior Vice President and Chief Engineer, NERC Howard Gugel, Vice President, NERC John Moura, Director, NERC Ryan Quint, Senior Manager, NERC Rich Bauer, Principal, NERC Matt Lewis, Manager, NERC As revised by the Project 2020-02 SAR Drafting Team		
Organization:	North American Electric Reliability Corporation		
Telephone:	Mark Lauby – 404-446-9723	Email:	mark.lauby@nerc.net
SAR Type (Check as many as apply)			
☒ New Standard ☒ Revision to Existing Standard ☒ Add, Modify, or Retire a Glossary Term *(as needed)* ☒ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The ERO Enterprise has analyzed over 10 disturbances involving widespread loss of solar photovoltaic (PV) resources and has published multiple disturbance reports highlighting key findings and recommendations from these analyses. Across all events, a widespread loss of generating resources – solar PV, wind, synchronous generation, and battery energy storage systems (BESS) – have abnormally tripped, ceased current injection, or reduced power output with control interactions. Generator ride-through is a foundational essential reliability service. BPS-connected generating resources remaining			

Requested information
connected during normal and contingency conditions is a critical component of BPS reliability. Ensuring fault ride-through capability enables dynamic reactive power support, frequency response, and other services. The unexpected loss of widespread generating assets poses a significant risk to BPS reliability. The existing PRC-024-3 is an equipment settings standard focused solely on voltage and frequency protection. However, this standard is serving little to no value in ensuring BPS-connected inverter-based resources remain connected and support the BPS during grid disturbances. Furthermore, NERC has experienced multiple asset owners during the event analyses who have misconstrued PRC-024-3, resulting in incorrect or unnecessary protections applied to generating assets that have resulted in spurious and abnormal tripping events. The systemic tripping and reductions of inverter-based resources, in addition to notable concurrent tripping or performance from synchronous generating resources, poses a risk to BPS reliability that must be addressed in a timely manner. This proposed standards project will address this known reliability risk with a more suitable performance-based standard that ensures generating resource ride-through performance for expected or planned BPS disturbances rather than focusing solely on a small subset of protections and controls that can trip generating resources.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The purpose of this SAR is to retire PRC-024-3 and replace it with a performance-based ride-through standard that ensures generators remain connected to the BPS during system disturbances. Specifically, this SAR focuses on the generator protection and control systems that can result in the reduction or disconnection of generating resources during these events. The SAR also ensures protection or controls that fail to ride through system events are analyzed, addressed with a corrective action plan (if possible), and reported to necessary entities for situational awareness. From a risk-based perspective, the goal of the standard is to mitigate the ongoing and systemic performance issues identified across multiple Interconnections and across many disturbances analyzed by NERC and the Regions. These issues have been identified in inverter-based resources as well as synchronous generators, with many causes of tripping entirely unrelated to voltage and frequency protection settings as dictated by the currently effective version of PRC-024.
Project Scope (Define the parameters of the proposed project):
The scope of this project includes the following: • Retire PRC-024-3, and create a new PRC standard or completely overhaul and replace the existing PRC-024 standard. • Allow for the possible modification or retirement of other relay-setting standards such as but not limited to PRC-006, PRC-019, PRC-025, and PRC-026, to prevent duplicative requirements and compliance obligations. • Creates a comprehensive, performance-based ride-through standard to ensure BES generating resources remain connected and providing essential reliability services during grid disturbances.

Requested information
• The scope of protections and controls involved in this ride-through standard shall include all generator protections and controls that affect the electrical output of the BES generating resource or plant. To be clear, the project should specify the protections and controls in the scope of the ride-through performance and define the term ride-through, as necessary. This should, at a minimum, include all generator (synchronous or inverter-based) protections and controls at the individual generators, at the inverters, or within the plant (i.e., plant-level controls and protections or collector system protections). • For synchronous generators, the scope of the ride-through standard shall explicitly exclude auxiliary systems and their protection systems. These protections have not posed a systemic BES reliability risk. However, protections and controls directly focused on the generator and its prime mover impacting the ride-through performance should be addressed in the standard. • For Inverter Based Resources (IBRs), auxiliary systems and their protection systems that can affect ride through performance shall be considered by the Standard Drafting Team. • The new standard shall ensure that all unexpected or abnormal tripping or reductions in power output are reported by the GO to the TOP, BA, and RC. • This team will also consider requirements for high-speed data recording relating to system events and will coordinate, as appropriate, with Project 2021-04 Modifications to PRC-002.
-Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide (1) a technical justification[1] that includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide the development of the Standard or definition):
The following describes the proposed deliverable for this project: • The proposed deliverable is a new NERC standard (or significant overhaul and revision of PRC-024-3) that includes the following key elements: ▪ A performance-based approach to generator ride-through rather than an equipment settings standard. The new standard shall include requirements that BES resources shall ride through grid disturbances and include quantitative measures (see below) on expectations for ride-through that address all possible causes of tripping and power reductions from BES generating resources (particularly generator, turbine, inverter, and all plant-level protection and controls). ▪ A reporting requirement that all trips or reductions in power output in response to grid disturbances are reported by the GO to the applicable TOP, BA, and RC ▪ A requirement that abnormal reductions in active power (i.e., tripping from protections or notable reductions from controls) in response to grid disturbances are analyzed by the GO to

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
develop and implement a Corrective Action Plan. Situations, where corrective action plans are not able to be developed, shall be reported to the TOP, BA, and RC. ▪ A clear requirement that momentary cessation, or temporary ceasing of current injection during BPS fault events, is deemed unacceptable performance for BES generating resources. Inverter-based generating resources employing momentary cessation shall develop a corrective action to mitigate its use. Legacy facilities that were connected before the effective date of the standard and cannot comply due to documented inherent equipment limitations, may be considered for an exemption; however, resources with a commercial operation date after the effective date of the standard (and possibly the PRC-024-3 implementation date) shall be required to eliminate the use of momentary cessation within "ride through envelopes" (e.g., the existing PRC-024 "No Trip Zone"). ▪ The terms ride-through, trip, momentary cessation, and any other relevant terms should be defined in the NERC Glossary of Terms if deemed necessary. ▪ A clear requirement that prolonged plant controller interactions that are unnecessary to protect equipment or system and impede the ability of the resource to dynamically respond to the grid disturbance and preclude the ability to fully provide essential reliability services are deemed unacceptable and should be addressed by a corrective action plan. ▪ A requirement that if the TOP, BA, or RC informs the GO of a tripping occurrence, cessation event, or plant controller interactions that are not reported by the GO, then the GO shall be responsible for analyzing the facility's performance during the event, developing a corrective action plan, and reporting this to the TOP, BA, and RC. The technical justification regarding the reliability-related need and benefits of this project are described in extensive detail in multiple NERC disturbance reports. All widespread solar PV loss events analyzed by the ERO Enterprise have involved extensive tripping and causes of reduction that is largely not addressed by PRC-024-3, many of which are unrelated to voltage and frequency tripping entirely. Furthermore, these multiple events have also involved the loss of synchronous generators for various reasons that should be considered in the development activities of this proposed project. Key disturbance reports include: • NERC 2021 California Disturbances Report (2022) • NERC Odessa Disturbance Report (2021) • NERC San Fernando Disturbance Report (2020) • NERC Palmdale Roost and Angeles Forest Disturbances Report (2019) • NERC Canyon 2 Fire Disturbance Report (2018) • NERC Blue Cut Fire Disturbance Report (2017) NERC Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources (2019), developed by the NERC Inverter-Based Resource Performance Working Group

Requested information
(IRPWG) and endorsed by the NERC Planning Committee, specifically recommends that all Transmission Owners (TOs) per FAC-001 establish or improve interconnection requirements by including quantitative requirements related to ride-through performance. Below is an excerpt from this guideline: *Quantitative requirements ensure that resources behave in a manner that supports BPS reliability and also assists the GOs and inverter manufacturers in specifying equipment to meet these requirements. These requirements may involve a performance envelope (FRT capability) that must be met by the resource, typically derived based on interconnection studies, grid codes, Reliability Standards, and other factors deemed necessary by the TO. Having these requirements ensures that the resources, particularly inverter-based resources, are unlikely to operate in a mode that has not been previously studied. Examples of these quantitative performance requirements include, but are not limited to, the following:* • *Pre- and post-fault short-circuit strength (equivalent impedance or short-circuit ratio (SCR)-based metric)) for worst-case contingency conditions* • *RMS low voltage ride-through and high voltage ride-through* • *Instantaneous transient overvoltage* • *Instantaneous change in phase angle* • *Low frequency ride-through and high frequency ride-through* • *No use of momentary cessation, by exception only* These deliverables developed by the ERO Enterprise and its stakeholder groups serve as a strong technical basis for ensuring resources successfully ride through grid disturbances and support the BPS by providing essential reliability services moving forward.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Incremental costs are expected for GOs that currently do not analyze the performance of their generating assets following grid disturbances, which has been shown during the NERC disturbance analyses to be a systemic reliability issue for solar PV resources in particular. GOs will need to assess their ride-through capabilities more comprehensively than in the past, which may have some associated costs. Minimal costs are associated with reporting of tripping occurrences. Facilities with abnormal or unexpected trips that can be mitigated with corrective actions will have some incremental costs; however, these improvements will help ensure adequate levels of reliability of the BES. Otherwise, cost impacts for this project are expected to be minimal. Additionally, if high speed data recording is not available in the required locations, entities may be required to install such equipment which would have some increased cost impact.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
BES generating resources.

Requested information
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Generator Owners, Generator Operators, Reliability Coordinators, Transmission Operators, Transmission Owners, Transmission Planners, Planning Coordinators
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This SAR is an outcome of ongoing analyses conducted by the ERO Enterprise regarding widespread inverter-based resource tripping events. Furthermore, the NERC IRPWG has developed comprehensive recommendations for improved performance of inverter-based resources, including the recommendation to develop comprehensive ride-through requirements.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
PRC-006, PRC-019, PRC—025, PRC-026
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
NERC has evaluated industry progress toward adopting the recommendations outlined in NERC guidelines, white papers, its prior Alerts, and other industry efforts. NERC believes that a nationwide standard for consistent requirements for generating resource ride-through is necessary to immediately address generating resource ride-through during grid disturbances moving forward.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for an emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
☐	5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Requested information	
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, and qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions from achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	None

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised

1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

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Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Generator Ride-Through Standard (PRC-024-3 Replacement)		
Date Submitted:	April 28, 2022		
SAR Requester			
Name:	Mark Lauby, Senior Vice President and Chief Engineer, NERC Howard Gugel, Vice President, NERC John Moura, Director, NERC Ryan Quint, Senior Manager, NERC Rich Bauer, Principal, NERC Matt Lewis, Manager, NERC		
Organization:	North American Electric Reliability Corporation		
Telephone:	Mark Lauby – 404-446-9723	Email:	mark.lauby@nerc.net
SAR Type (Check as many as apply)			
☒ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term *(as needed)* ☒ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The ERO Enterprise has analyzed over 10 disturbances involving widespread loss of solar photovoltaic (PV) resources and has published multiple disturbance reports highlighting key findings and recommendations from these analyses. Across all events, a widespread loss of generating resources – solar PV, wind, synchronous generation, and battery energy storage systems (BESS) – have abnormally tripped, ceased current injection, or reduced power output with control interactions. Generator ride-through is a foundational essential reliability service. BPS-connected generating resources remaining connected during normal and contingency conditions is a critical component of BPS reliability. Ensuring fault ride-through capability enables dynamic reactive power support, frequency response, and other			

Requested information
services. The unexpected loss of widespread generating assets poses a significant risk to BPS reliability. The existing PRC-024-3 is an equipment settings standard focused solely on voltage and frequency protection. However, this standard is serving little to no value for ensuring BPS-connected inverter-based resources remain connected and supporting the BPS during grid disturbances. Furthermore, NERC has experienced multiple asset owners during the event analyses who have misconstrued PRC-024-3, resulting in incorrect or unnecessary protections applied to generating assets that have resulted in spurious and abnormal tripping events. The systemic tripping and reductions of inverter-based resources, in addition to notable concurrent tripping or performance from synchronous generating resources poses a risk to BPS reliability that must be addressed in a timely manner. This proposed standards project will address this known reliability risk with a more suitable performance-based standard that ensures generating resource ride-through performance for expected or planned BPS disturbances rather than focusing solely on a small subset of protections and controls that can trip generating resources.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The purpose of this SAR is to retire PRC-024-3 and replace it with a performance-based ride-through standard that ensures generators remain connected to the BPS during system disturbances. Specifically, this SAR focuses on the generator protection and control systems that can result in the reduction or disconnection of generating resources during these events. The SAR also ensures protection or controls that fail to ride through system events are analyzed, addressed with a corrective action plan (if possible), and reported to necessary entities for situational awareness. From a risk-based perspective, the goal of the standard is to mitigate the ongoing and systemic performance issues identified across multiple Interconnections and across many disturbances analyzed by NERC and the Regions. These issues have been identified in inverter-based resources as well as synchronous generators, with many causes of tripping entirely unrelated to voltage and frequency protection settings as dictated by the currently effective version of PRC-024.
Project Scope (Define the parameters of the proposed project):
The scope of this project includes the following: • Retire PRC-024-3, and create a new PRC standard or completely overhaul and replace the existing PRC-024 standard. • Allow for the possible modification or retirement of other relay setting standards such as but not limited to PRC-006, PRC-019, PRC-025, and PRC-026, to prevent duplicative requirements and compliance obligations. • Creates a comprehensive, performance-based ride-through standard with the purpose of ensuring BES generating resources remain connected and providing essential reliability services during grid disturbances. • The scope of protections and controls involved in this ride-through standard shall include all generator protections and controls that affect the electrical output of the BES generating resource

Requested information

or plant. To be clear, the project should specify the protections and controls in scope of the ride-through performance and define the term ride-through, as necessary. This should, at a minimum, include all generator (synchronous or inverter-based) protections and controls at the individual generators, at the inverters, or within the plant (i.e., plant-level controls and protections or collector system protections).

- For synchronous generators, ~~T~~the scope of the ride-through standard shall explicitly exclude auxiliary systems and their protection systems. ~~Abnormal performance or unexpected tripping of t~~These protections have ~~do~~ not posed a systemic BES reliability risk. However, protections and controls directly focused on the generator and its prime mover impacting the ride-through performance should be addressed in the standard. ~~(e.g., overspeed, power-load imbalance, overvoltage, pole out of step slipphase jump, overcurrent) or plant-level (e.g., voltage, current, frequency, phase, etc.) have posed notable risks to BES reliability and should be addressed directly in this standard.~~
- For Inverter Based Resources (IBRs), auxiliary systems and their protection systems that can affect ride through performance shall be considered by the Standard Drafting Team.
- The new standard shall ensure that all unexpected or abnormal tripping or reductions in power output are reported by the GO to the TOP, BA, and RC.
- This team will also consider requirements for high speed data recording relating to system events and will coordinate, as appropriate, with Project 2021-04 Modifications to PRC-002.

-Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):

The following describe the proposed deliverable for this project:

- The proposed deliverable is a new NERC standard (or significant overhaul and revision of PRC-024-3) that includes the following key elements:
  - A performance-based approach to generator ride-through rather than an equipment settings standard. The new standard shall include requirements that BES resources shall ride through grid disturbances and include quantitative measures (see below) on expectations for ride-through that address all possible causes of tripping and power reductions from BES generating resources (particularly generator, turbine, inverter, and all plant-level protection and controls).
  - A reporting requirement that all trips or reductions in power output in response to grid disturbances are reported by the GO to the applicable TOP, BA, and RC

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information

- ~~A reporting requirement that all trips or reductions in power output are reported by the GO to the TOP, BA, and RC.~~
- A requirement that abnormal reductions in active power (i.e., tripping from protections or notable reductions from controls) in response to grid disturbances are analyzed by the GO to develop and implement a C~~c~~orrective A~~a~~ction P~~p~~lan~~, if possible~~. Situations where corrective action plans are not able to be developed shall be reported to the TOP, BA, and RC.
- A clear requirement that momentary cessation, or temporary ceasing of current injection during BPS fault events, is deemed unacceptable performance for BES generating resources. Inverter-based generating resources employing momentary cessation shall develop a corrective action to mitigate its use. Legacy facilities that were connected prior to the effective date of the standard and cannot comply due to documented inherent equipment limitations, may be considered for ~~should receive~~ an exemption; however, resources with a commercial operation date after the effective date of the standard (and possibly the PRC-024-3 implementation date) shall be required to eliminate the use of momentary cessation within "ride through envelopes" (e.g., the existing PRC-024 "No Trip Zone").
- The terms ride-through, trip, momentary cessation, and any other relevant terms should be defined in the NERC Glossary of Terms, if deemed necessary.
- A clear requirement that prolonged plant controller interactions that are unnecessary to protect equipment or system and impede the ability of the resource to dynamically respond to the grid disturbance and preclude the ability to fully provide essential reliability services are deemed unacceptable and should be addressed by a corrective action plan.
- A requirement that if the TOP, BA, or RC inform the GO of a tripping occurrence, cessation event, or plant controller interactions that are not reported by the GO, then the GO shall be responsible for analyzing the facility's performance during the event, developing a corrective action plan, and reporting this to the TOP, BA, and RC.

The technical justification regarding the reliability-related need and benefits of this project are described in extensive detail in multiple NERC disturbance reports. All widespread solar PV loss events analyzed by the ERO Enterprise have involved extensive tripping and causes of reduction that are largely not address by PRC-024-3, many of which are unrelated to voltage and frequency tripping entirely. Furthermore, these multiple events have also involved the loss of synchronous generators for various reasons that should be considered in the development activities of this proposed project. Key disturbance reports include:

- NERC 2021 California Disturbances Report (2022)
- NERC Odessa Disturbance Report (2021)
- NERC San Fernando Disturbance Report (2020)
- NERC Palmdale Roost and Angeles Forest Disturbances Report (2019)
- NERC Canyon 2 Fire Disturbance Report (2018)

Requested information
• NERC Blue Cut Fire Disturbance Report (2017) NERC Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources (2019), developed by the NERC Inverter-Based Resource Performance Working Group (IRPWG) and endorsed by the NERC Planning Committee, specifically recommends that all Transmission Owners (TOs) per FAC-001 establish or improve interconnection requirements by including quantitative requirements related to ride-through performance. Below is an excerpt from this guideline: *Quantitative requirements ensure that resources behave in a manner that supports BPS reliability and also assists the GOs and inverter manufacturers in specifying equipment to meet these requirements. These requirements may involve a performance envelope (FRT capability) that must be met by the resource, typically derived based on interconnection studies, grid codes, Reliability Standards, and other factors deemed necessary by the TO. Having these requirements ensures that the resources, particularly inverter-based resources, are unlikely to operate in a mode that has not been previously studied. Examples of these quantitative performance requirements include, but are not limited to, the following:* • *Pre- and post-fault short-circuit strength (equivalent impedance or short-circuit ratio (SCR)-based metric)) for worst case contingency conditions* • *RMS low voltage ride-through and high voltage ride-through* • *Instantaneous transient overvoltage* • *Instantaneous change in phase angle* • *Low frequency ride-through and high frequency ride-through* • *No use of momentary cessation, by exception only* These deliverables developed by the ERO Enterprise and its stakeholder groups serve as a strong technical basis for ensuring resources successfully ride through grid disturbances and support the BPS by providing essential reliability services moving forward.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Incremental costs are expected for GOs that currently do not analyze the performance of their generating assets following grid disturbances, which has been shown during the NERC disturbance analyses to be a systemic reliability issue for solar PV resources in particular. GOs will need to assess their ride-through capabilities more comprehensively than in the past, which may have some associated costs. Minimal costs are associated with reporting of tripping occurrences. Facilities with abnormal or unexpected trips that can be mitigated with corrective actions will have some incremental costs; however, these improvements will help ensure adequate levels of reliability of the BES. Otherwise, cost impacts for this project are expected to be minimal. Additionally, if high speed data recording is not available on the required locations, entities may be required to install such equipment which would have some increased cost impact.

Requested information
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
BES generating resources.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Generator Owners, Generator Operators, Reliability Coordinators, Transmission Operators, Transmission Owners, Transmission Planners, Planning Coordinators
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This SAR is an outcome of ongoing analyses conducted by the ERO Enterprise regarding widespread inverter-based resource tripping events. Furthermore, the NERC IRPWG has developed comprehensive recommendations for improved performance of inverter-based resources, including the recommendation to develop comprehensive ride-through requirements.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
PRC-006, PRC-019, PRC—025, PRC-026~~No.~~
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
NERC has evaluated industry progress toward adopting the recommendations outlined in NERC guidelines, white papers, its prior Alerts, and other industry efforts. NERC believes that a nationwide standard for consistent requirements for generating resource ride-through is necessary to immediately address generating resource ride-through during grid disturbances moving forward.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Requested information	
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following [Market Interface Principles]?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	None

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Agenda Item 8
Standards Committee
December 13, 2023

Project 2020-02 Modifications to PRC-024 (Generator Ride-through) Waiver

Action

- Approve the following waiver of provisions of the Standard Processes Manual (SPM) for Project 2020-02:
  - Initial formal comment and ballot period reduced from 45 days to as few as 25 calendar days, with ballot pools formed in the first 10 days and initial ballot and non-binding poll of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) conducted during the last 10 days of the comment period (Sections 4.7 and 4.9)
  - Additional formal comment and ballot period(s) reduced from 45 days to as few as 15 calendar days, with ballot(s) conducted during the last 5 days of the comment period. (Sections 4.9 and 4.12)
  - Final ballot reduced from 10 days to 5 calendar days. (Section 4.9)

Background

The SAR ensures generators remain connected to the bulk power system (BPS) during system disturbances. Specifically, this SAR focuses on the generator protection and control systems that can result in the reduction or disconnection of generating resources during these events. The SAR also ensures that protection or controls that fail to ride through system events are analyzed, addressed with a corrective action plan (if possible), and reported to necessary entities for situational awareness. However, those items are now covered within Project 2023-02. From a risk-based perspective, the goal of the standard is to mitigate the ongoing and systemic performance issues identified across multiple Interconnections and across many disturbances analyzed by NERC and the Regions. These issues have been identified in Inverter-Based Resources (IBR) and synchronous generators, with many causes of tripping entirely unrelated to voltage and frequency protection settings as dictated by the currently effective version of PRC-024.

At the April 19, 2023 meeting, the Standards Committee (SC) accepted the most recent revised SAR submitted by the Project 2020-02 Standard Drafting Team.

NERC Standard Processes Manual Section 16.0 Waiver provides as follows:

> The SC may waive any of the provisions contained in this manual for good cause shown, but limited to the following circumstances:
>
> - In response to a national emergency declared by the United States or Canadian governments that involves the reliability of the Bulk Electric System (BES) or cyber attack on the BES;
> - Where necessary to meet regulatory deadlines;
> - Where necessary to meet deadlines imposed by the NERC Board of Trustees; or

- Where the SC determines that a modification to a proposed Reliability Standard or its requirement(s), a modification to a defined term, a modification to an Interpretation, or a modification to a variance has already been vetted by the industry through the standards development process or is so insubstantial that developing the modification through the processes contained in this manual will add significant time delay.

FERC Order 901 directs the development of new or modified reliability standards that include new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. This set of directives from the report comprises the first three sets of Standards Projects that must be completed and filed with FERC. This first set (disturbance monitoring data sharing and post-event performance validation and correction of IBR performance) must be filed with FERC by November 4, 2024.

NERC Standards Development has identified three active projects (2020-02, 2021-04, and 2023-02) that are directly impacted by these associated FERC directives. Project 2020-02 DT leadership and NERC staff request that the SC approve a waiver for specific provisions of the SPM regarding the length of comment periods and ballots in order to meet the November 2024 development deadline for 2020-02 as established by FERC.

Summary

Project 2020-02 DT leadership and NERC staff recommend that the SC shorten the initial formal comment and ballot period from 45 days to as few as 25 days and any additional formal comment and ballot period(s) from 45 days to as few as 15 days. In addition, Project 2020-02 DT leadership and NERC staff recommend that the SC shorten the final ballot from 10 days to 5 days.

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-024-4 is posted for a 25-day formal comment period with initial ballot.

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023

Anticipated Actions	Date
25-day formal comment period with initial ballot	March 27 - April 22, 2024
15-day formal comment period and additional ballot	May 20 - June 4, 2024
15-day formal comment period and additional ballot	July 1 - 16, 2024
Final Ballot	July 18 - 24, 2024
Board adoption	August 14, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

A. Introduction

1. **Title:** Frequency and Voltage Protection Settings for Synchronous Generators and Synchronous Condensers

2. **Number:** PRC-024-4

3. **Purpose:** To assure that protection of synchronous generators and synchronous condensers do not cause tripping during defined frequency and voltage excursions in support of the Bulk Power System (BPS).

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Generator Owners that apply protection listed in Sections 4.2.1 or 4.2.2.

4.1.2. Transmission Owners that apply protection listed in Section 4.2.2.

4.1.3. 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.

4.1.4. 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 trip; and are applied to the following:

4.2.1.1 Bulk Electric System (BES) synchronous generators.

4.2.1.2 BES GSU transformer(s) for synchronous generators.

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

4.2.1.4 Elements that are designed primarily for the delivery of capacity from multiple synchronous generators connecting to a common bus identified in the BES Definition, Inclusion I4, to the point where those resources aggregate to greater than 75 MVA.

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[1] For the purpose of this standard, the MPT is the power transformer that steps up voltage from multiple small synchronous generators, e.g. multiple small hydro generators connecting to a common bus.

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

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

4.2.1.5 MPT of multiple synchronous generators connecting to a common bus as identified in the BES Definition, Inclusion I4.

4.2.2 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 transmission connected synchronous condensers; or (ii) provide signals to trip transmission connected synchronous condenser and are applied to the following:

4.2.2.1 BES synchronous condensers

4.2.2.2 BES step-up transformer(s) for synchronous condensers.

4.2.2.3 High-side of the synchronous condenser-connected unit auxiliary transformer (UAT).

4.2.3 **Exemptions:** Protection on all auxiliary equipment within the synchronous generator or synchronous condenser Facility.

5. **Effective Date:** See Implementation Plan for PRC-024-4

B. Requirements and Measures

R1. Each Generator Owner and Transmission Owner shall set applicable frequency protection[4] in accordance with PRC-024 Attachment 1 such that the applicable protection does not cause the synchronous generator(s) or condenser(s) to trip within the "no trip zone" during a frequency excursion with the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Applicable frequency protection may be set to trip within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M1. Each Generator Owner and Transmission Owner shall have evidence that the applicable frequency protection has been set in accordance with Requirement R1, such as dated setting sheets, calibration sheets, calculations, or other documentation.

R2. Each Generator Owner and Transmission Owner shall set applicable voltage protection[5] in accordance with PRC-024 Attachment 2, such that the applicable protection does not cause the synchronous generator(s) or condenser(s) to trip within the "no trip zone" during a voltage excursion at the high-side of the GSU or MPT, 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 or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- Applicable voltage protection may be set to trip during a voltage excursion within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M2. 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.

R3. Each Generator Owner and Transmission Owner shall document each known regulatory or equipment limitation[6] that prevents an applicable synchronous generator(s) or condenser(s) with frequency or voltage protection from meeting the 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]*

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[4] 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 synchronous generator(s) or condenser(s); or (ii) provide signals to the synchronous generator(s) or condenser(s) to trip.
[5] Ibid.
[6] Excludes limitations caused by the setting capability of the frequency, voltage, and volts per hertz protective relays for the synchronous generator(s) or condenser(s). This does not exclude limitations originating in the equipment protected by the relay.

3.1. The Generator Owner and Transmission 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 and Transmission Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations 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.

R4. Each Generator Owner and Transmission Owner shall provide its applicable protection settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated synchronous generator(s) or condenser(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 settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of protection setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Generator Owner and Transmission Owner shall have evidence that it communicated applicable 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.

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.

1.2. Evidence Retention: 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 and Transmission Owner shall keep data or evidence of Requirements R1 through R4 for five years or until the next audit, whichever is longer.
- If a Generator Owner or Transmission 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.

1.3. Compliance Monitoring and Enforcement 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.

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 or Transmission Owner failed to set its applicable frequency protection so that it does not trip according to Requirement R1.
R2.	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 according to Requirement R2.
R3.	The Generator Owner or Transmission 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 or Transmission 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 or Transmission 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 or Transmission 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 or Transmission Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				days of identifying the limitation.
R4.	The Generator Owner or Transmission Owner provided its protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner or provided protection settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner or Transmission Owner failed to provide its protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner failed to provide protection settings within 150 calendar days of a written request.

D. Regional Variances

D.A. Variance for the Quebec Interconnection

This Variance 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.

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

D.A.2. Each Generator Owner and Transmission Owner shall set applicable voltage protection[6] in accordance with PRC-024 Attachment 2B, such that the applicable protection does not cause the synchronous generator(s) or condenser(s) to trip within the "no trip zone" during a voltage excursion 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".
- Synchronous generator(s) are permitted to be set to trip during a voltage excursion bounded by the "no trip zone" of PRC-024 Attachment 2B 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 2B, then the Generator Owner or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.

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 2B and notify, within 30 calendar days of its designation, each Generator Owner or Transmission Owner that owns facilities[7] in the

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

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.

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 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 facilities in the strategic power plants between 31 days and 45 days after its designation.	The Planning Coordinator designated strategic power plants at least once every five calendar years but notified each Generator Owner or Transmission Owner that owns facilities in the strategic power plants between 46 days and 60 days after its designation.	The Planning Coordinator failed to designate, at least once every five years, the strategic power plants that must comply with Attachment 2B. 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 its designation.

E. Associated Documents

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	February 6, 2020	Adopted by the NERC Board of Trustees	Standard revised in Project 2018-04
3	July 9, 2020	FERC Letter Order approved PRC-024-3. Docket No. RD20-7-000	
3	July 17, 2020	Effective Date	10/1/2022

Attachment 1

(Frequency No Trip Boundaries by Interconnection[8])

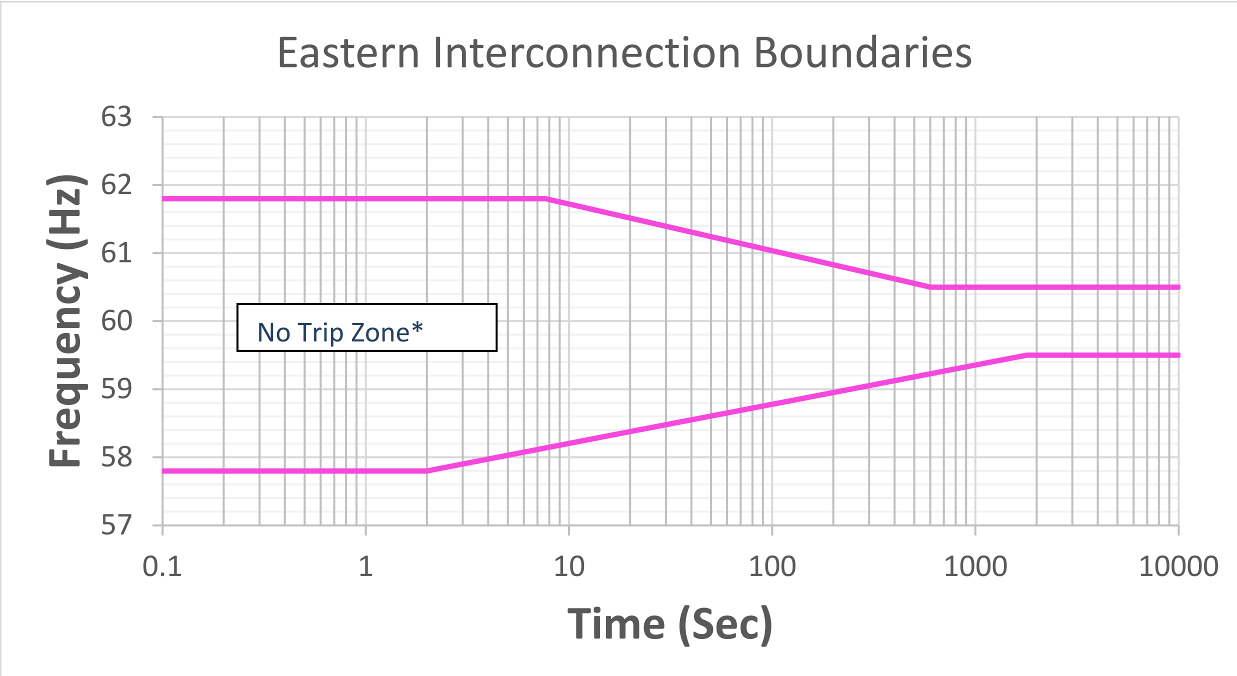

Figure 1.1

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

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]	≤57.8	Instantaneous[11]
≥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 1.2

[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.

[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.

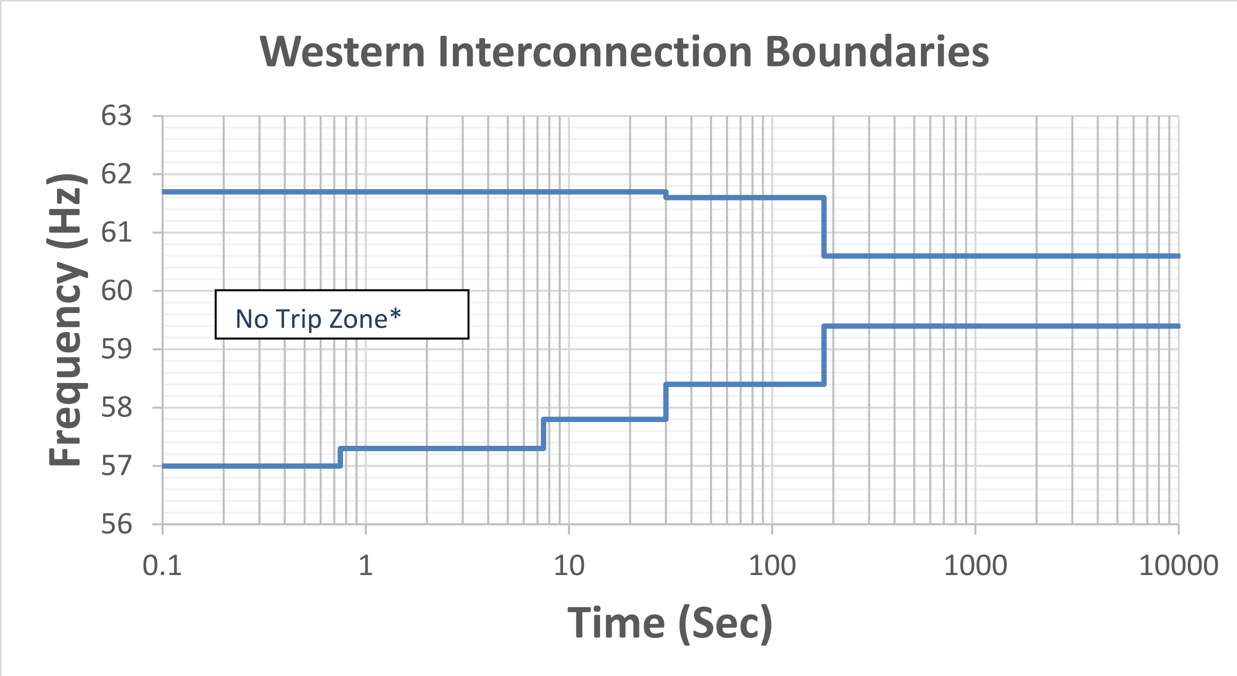

Figure1.3

**** 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[11]	≤57.0	Instantaneous[11]
≥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 1.4

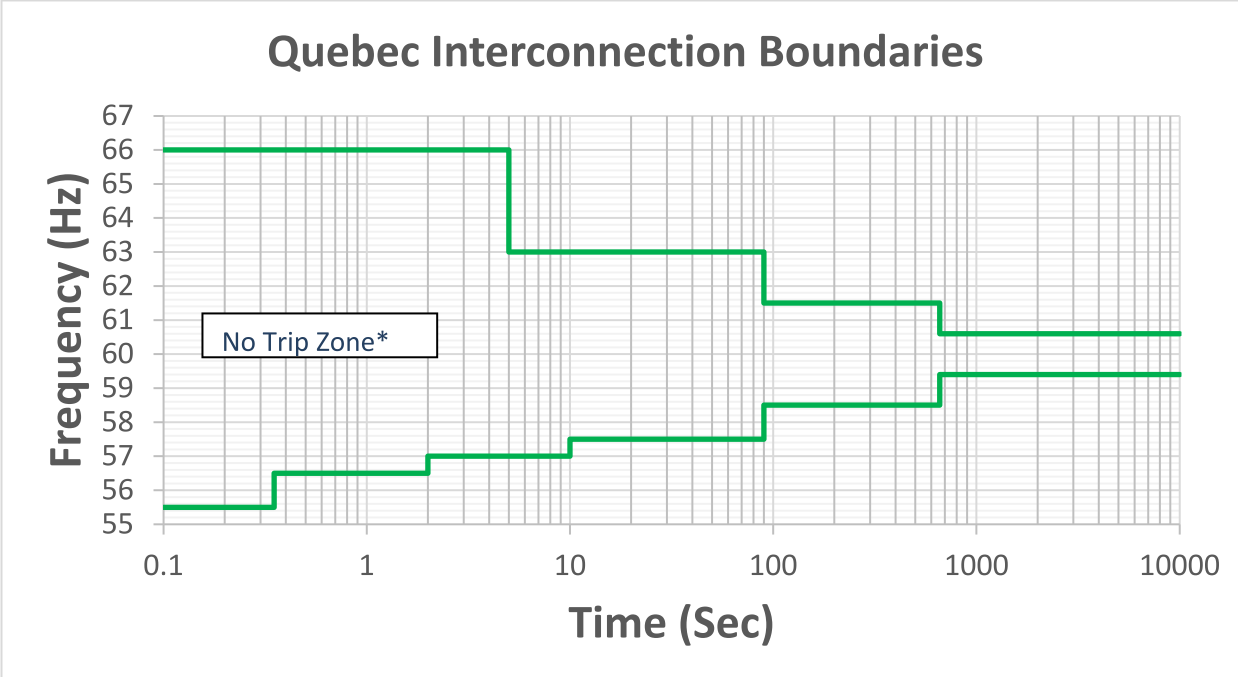

Figure 1.5

***** 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[11]	<55.5	Instantaneous[11]
≥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 1.6

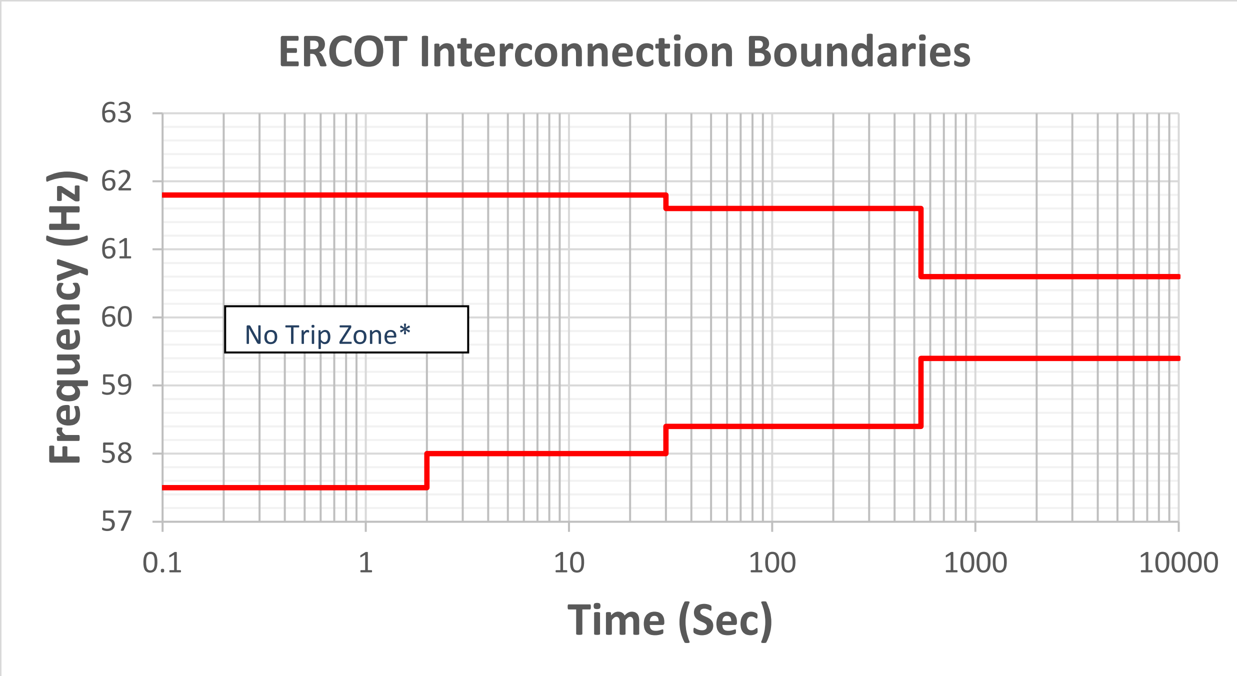

Figure 1.7

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[11]	≤57.5	Instantaneous[11]
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

Table 1.8

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

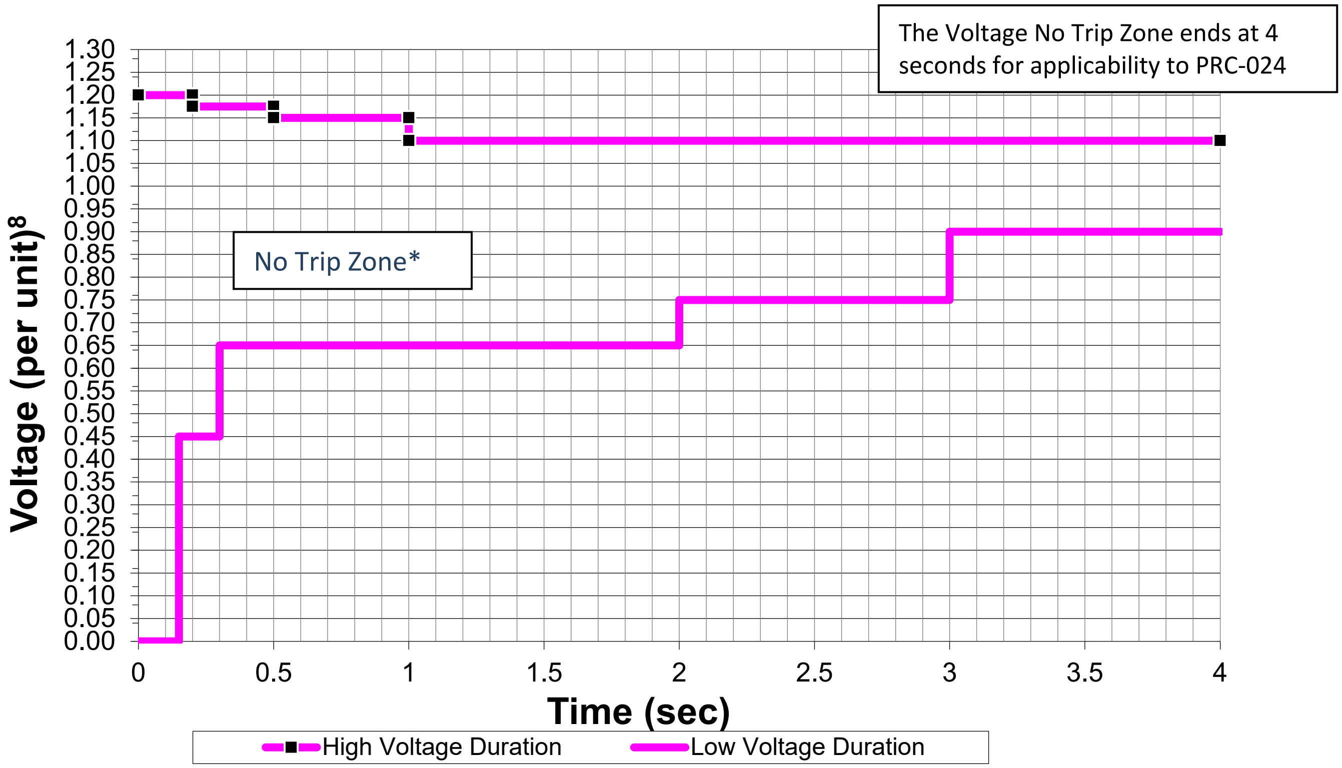

Figure 2.1

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

Voltage Boundary Data Points

High Voltage Duration		Low Voltage Duration	
Voltage (per unit)	Minimum Time (sec)	Voltage (per unit)	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 2.2

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

Attachment 2A: Voltage Boundary Clarifications
(Eastern, Western, and ERCOT Interconnections)

Boundary Details:

1. Unless otherwise specified by the Transmission Planner, the per unit voltage base for these boundaries is the nominal transmission system voltage (e.g., 100 kV, 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 400 kV, 500 kV, 765 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 boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase per unit voltage.
5. For applicability to PRC-024, the “no trip zone” ends at 4 seconds.

Evaluating Protection Settings

The voltage values in the Attachment 2 voltage boundaries are voltages at the high-side of the GSU/MPT. For 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 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.

Attachment 2B

(Voltage No-Trip Boundaries – Quebec Interconnection)

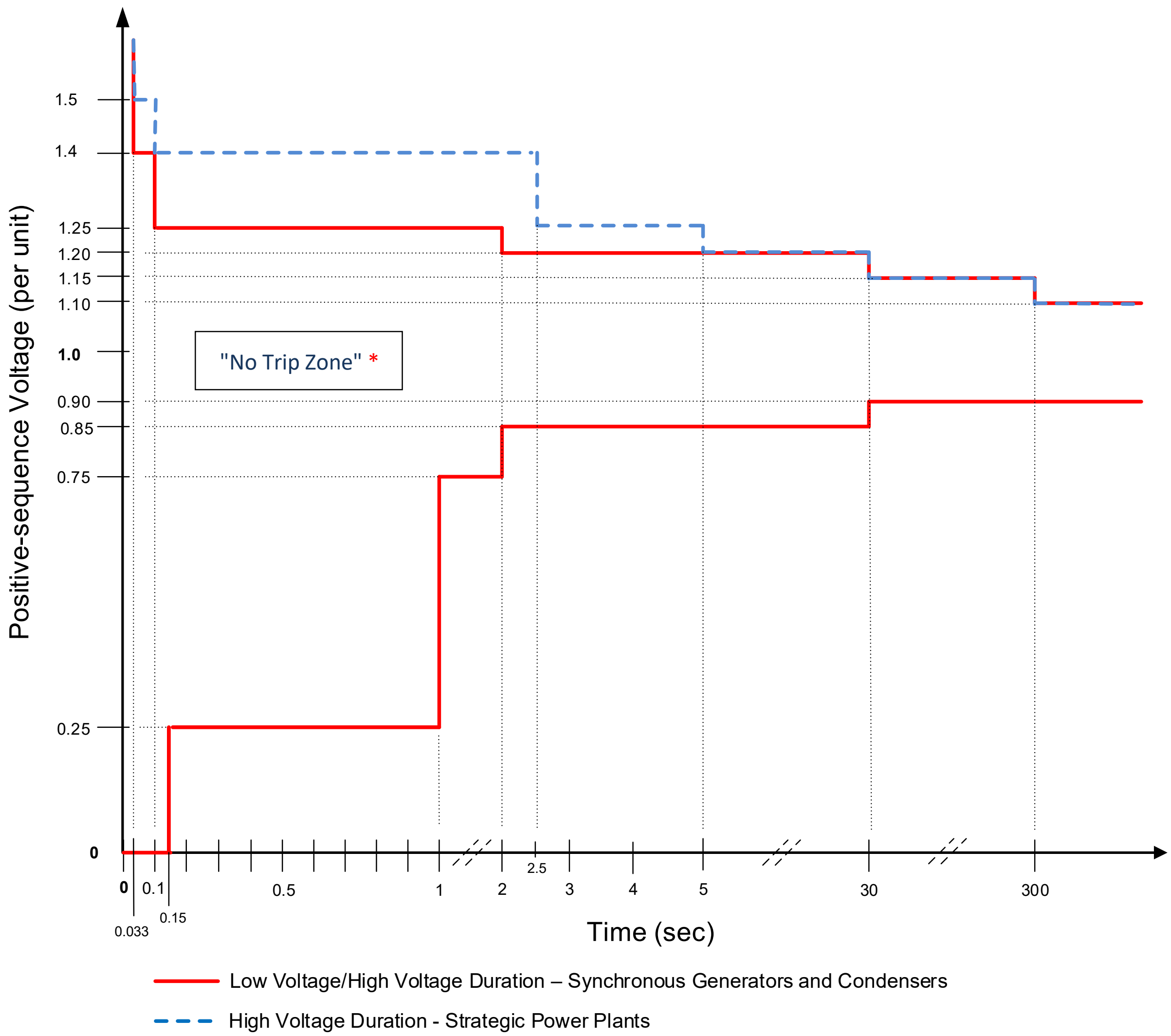

Figure 1

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

Voltage Boundary Data Points – Quebec Interconnection

High Voltage Duration for all Synchronous Generators and Condensers		High Voltage Duration for strategic[1] Power Plants	
Voltage (per unit)	Minimum Time (sec)	Voltage (per unit)	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 Synchronous Generators and Condensers	
Voltage (per unit)	Minimum Time (sec)
<0.25	0.15
<0.75	1.00
<0.85	2.00
<0.90	30
≥0.90	continuous

Table 2

Attachment 2C
(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 2B voltage boundaries are voltages at the high-side of the GSU/MPT. For 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.

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-024-4 is posted for a 25-day formal comment period with initial ballot.

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023

Anticipated Actions	Date
25-day formal comment period with initial ballot	March 27, 2024 - April 22, 2024
15-day formal comment period and additional ballot	May 20, 2024 – June 4, 2024
15-day formal comment period and additional ballot	July 1, 2024 – July 16, 2024
Final Ballot	July 18, 2024 – July 24, 2024
Board adoption	August 14, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

A. Introduction

1. **Title:** Frequency and Voltage Protection Settings for ~~Generating Resources~~Synchronous Generators and Synchronous Condensers

2. **Number:** PRC-024-4~~3~~

3. **Purpose:** To ~~set~~ assure that protection of ~~S~~synchronous ~~G~~generators and ~~S~~synchronous ~~C~~condensers ~~generating resource(s) remain connected~~ does not cause tripping during defined frequency and voltage excursions in support of the Bulk ~~Electric System~~Power System (B~~E~~PS).

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owners that apply protection listed in Sections 4.2.1 or 4.2.2.

   ~~**4.1.1.**~~**4.1.2.** Transmission Owners that apply protection listed in Section 4.2.2.

   ~~**4.1.2.**~~**4.1.3.** 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.**~~**4.1.4.** 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 Bulk Electric System (BES) synchronous generators~~generating resource(s)~~.

   4.2.1.2 BES GSU transformer(s) for synchronous generators.

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

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[1] For the purpose of this standard, the MPT is the power transformer that steps up voltage from multiple small synchronous generators, e.g. multiple small hydro generators connecting to a common bus. ~~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 variously ~~ably~~ referred to as station power UAT, or station service transformer(s) used to provide overall auxiliary power to the ~~generating resource(s)~~synchronous generators. This UAT is the transformer connected on the generator bus between the low side of the GSU and the generator terminal.

~~4.2.1.4 Individual synchronous generators utilized as dispersed power producing resource(s) identified in the BES Definition, Inclusion I4.~~

~~4.2.1.5~~4.2.1.4 Elements that are designed primarily for the delivery of capacity from ~~the individualispersed power producing resources~~ multiple synchronous generators connecting to a common bus identified in the BES Definition, Inclusion I4, to the point where those resources aggregate to greater than 75 MVA.

4.2.1.5 MPT[4] of multiple synchronous generators connecting to a common bus ~~utilized as dispersed power producing resources resource(s)~~ as identified in the BES Definition, Inclusion I4.

4.2.2 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 tranmission connected synchronous condensers; or (ii) provide signals to trip transmission connected synchronous condenser and are applied to the following:

4.2.2.1 BES synchronous condensers

4.2.2.2 BES step-up transformer(s) for synchronous condensers.

~~4.2.1.6~~4.2.2.3 High--side of the synchronous condenser-connected unit auxiliary transformer[5] (UAT).

~~4.2.2~~4.2.3 **Exemptions:** Protection on all auxiliary equipment within the synchronous generator or synchronous condenser ~~generating~~ Facility.

5. **Effective Date:** See Implementation Plan for PRC-024-4~~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.~~

~~[5] These transformers are variably referred to as station power UAT, or station service transformer(s) used to provide overall auxiliary power to the synchronous condenser~~

B. Requirements and Measures

R1. Each Generator Owner and Transmission Owner shall set ~~its~~ applicable frequency protection[6] in accordance with PRC-024 Attachment 1 such that the applicable protection does not cause the ~~generating~~ synchronous generator(s) or condenser(s) to trip ~~or cease injecting current~~ within the "no trip zone" during a frequency excursion with the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Applicable frequency protection may 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.

M1. Each Generator Owner and Transmission Owner- shall have evidence that the applicable frequency protection has been set in accordance with Requirement R1, such as dated setting sheets, calibration sheets, calculations, or other documentation.

R2. Each Generator Owner and Transmission Owner shall set ~~its~~ applicable voltage protection[7] in accordance with PRC-024 Attachment 2, such that the applicable protection does not cause the ~~generating resource~~ synchronous generator(s) or condenser(s) -to trip ~~or cease injecting current~~ within the "no trip zone" during a voltage excursion at the high--side of the GSU or MPT, 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 or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- Applicable voltage protection may be set to trip ~~or cease injecting current~~ during a voltage excursion within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M2. 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.

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[6] 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)~~ synchronous generator(s) or condenser(s); or (ii) provide signals to the ~~generating resource(s)~~ synchronous generator(s) or condenser(s) to ~~either~~ trip ~~or cease injecting current~~.

[7] Ibid.

R3. Each Generator Owner and Transmission Owner shall document each known regulatory or equipment limitation[8] that prevents an applicable ~~generating resource(s)~~ synchronous generator(s) or condenser(s) with frequency or voltage protection from meeting the 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]*

3.1. The Generator Owner and Transmission 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 and Transmission Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations 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.

R4. Each Generator Owner and Transmission Owner shall provide its applicable protection settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated ~~generating resource(s)~~ synchronous generator(s) or condenser(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 settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of protection setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Generator Owner and Transmission Owner shall have evidence that it communicated applicable 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.

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

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.

   1.2. **Evidence Retention:** 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 and Transmission Owner shall keep data or evidence of Requirements R1 through R4 for ~~3~~five years or until the next audit, whichever is longer.
   - If a Generator Owner or Transmission 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.

   1.3. **Compliance Monitoring and Enforcement 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.

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 or Transmission Owner failed to set its applicable frequency protection so that it does not trip ~~or enter momentary cessation~~ according to Requirement R1.
R2.	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 enter momentary cessation~~ according to Requirement R2.
R3.	The Generator Owner or Transmission 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	The Generator Owner or Transmission 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	The Generator Owner or Transmission 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	The Generator Owner or Transmission 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 or Transmission Owner failed to communicate the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	but less than or equal to 60 calendar days of identifying the limitation.	but less than or equal to 90 calendar days of identifying the limitation.	but less than or equal to 120 calendar days of identifying the limitation.	documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4.	The Generator Owner or Transmission Owner provided its protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner or provided protection settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner or Transmission Owner failed to provide its protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner failed to provide protection settings within 150 calendar days of a written request.

D. Regional Variances

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[6]~~[5]~~ in accordance with PRC-024 Attachment 2B~~a~~, such that the applicable protection does not cause the ~~generating resource~~synchronous generator(s) or condenser(s) to trip ~~or cease injecting current~~ within the “no trip zone” 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)~~Synchronous generator(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 2B~~a~~ 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 2B~~a~~, 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 2B~~a~~ and notify, within 30 calendar days of its designation, each Generator Owner or Transmission Owner that owns facilities[9] 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.

[9] Facilities in the strategic power plants include facilities with synchronous generator(s) 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 enter momentary cessation~~ 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 2B~~a~~.

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.

E. Associated Documents

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	February 6, 2020	Adopted by the NERC Board of Trustees	Standard revised in Project 2018-04
3	July 9, 2020	FERC Letter Order approved PRC024-3. Docket No. RD20-7-000	
3	July 17, 2020	Effective Date	10/1/2022

Attachment 1

(Frequency No Trip Boundaries by Interconnection[10])

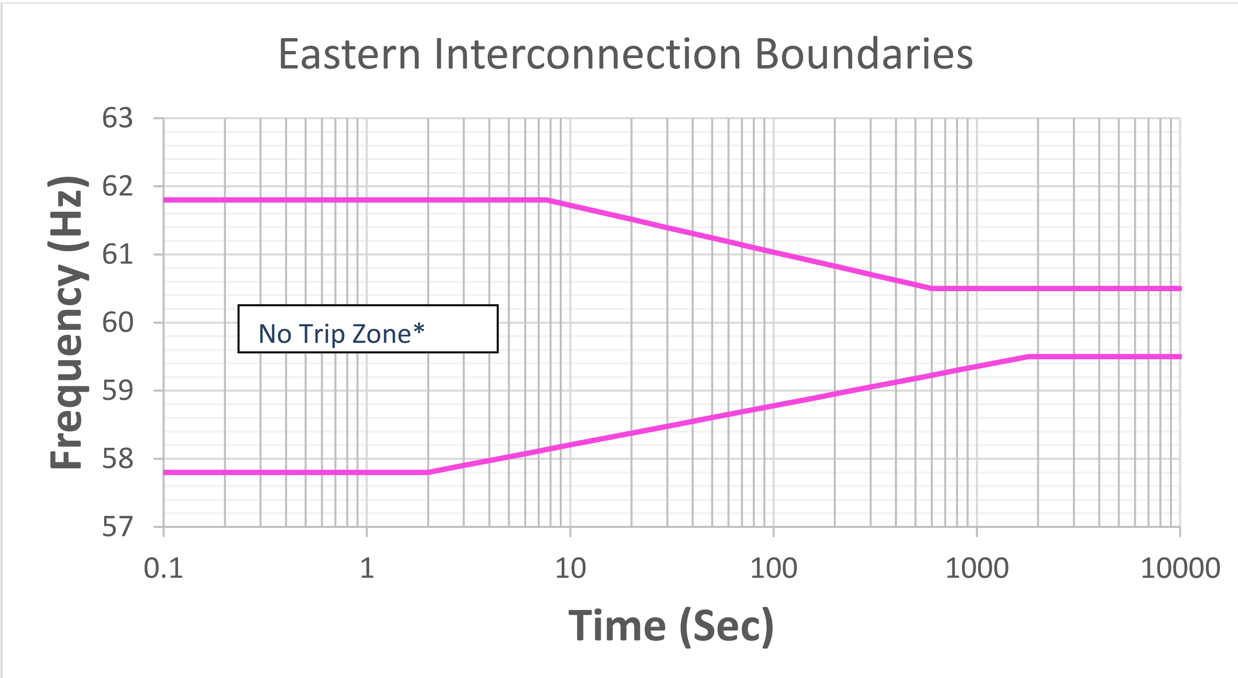


Figure 1.1

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

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[11]	≤57.8	Instantaneous[11]
≥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 1.2

[10] 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.

[11] 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.

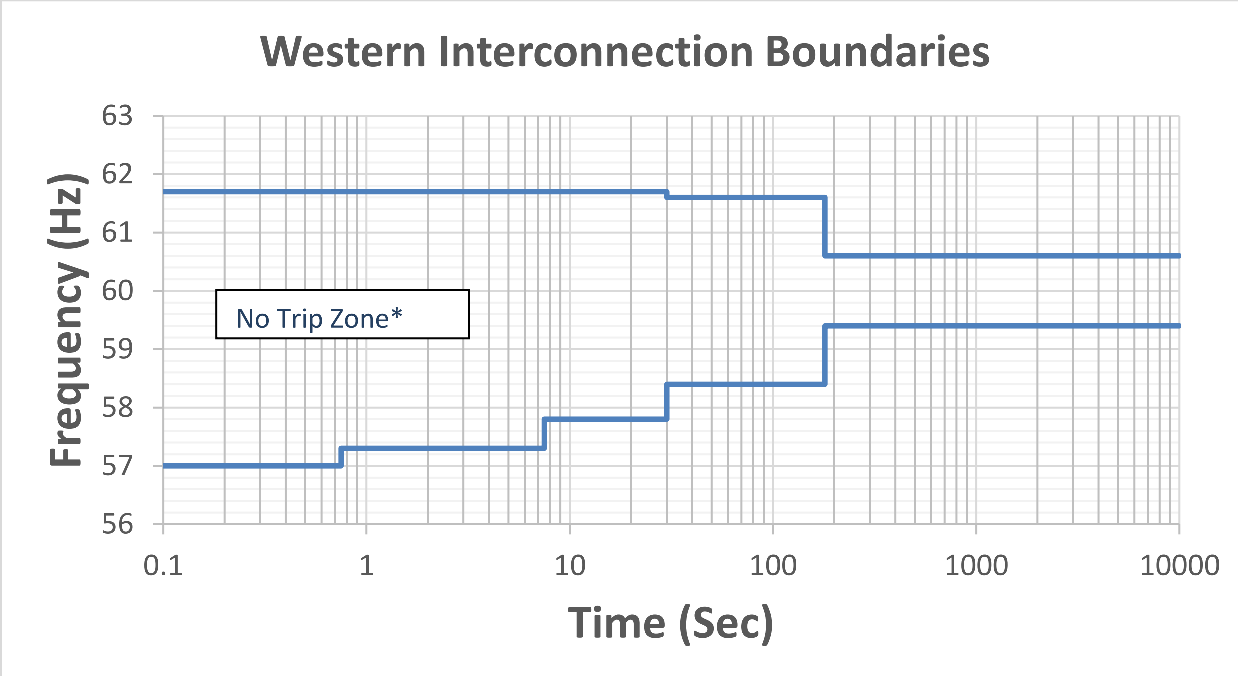


Figure ~~2~~1.3

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[11]	≤57.0	Instantaneous[11]
≥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~~1.4

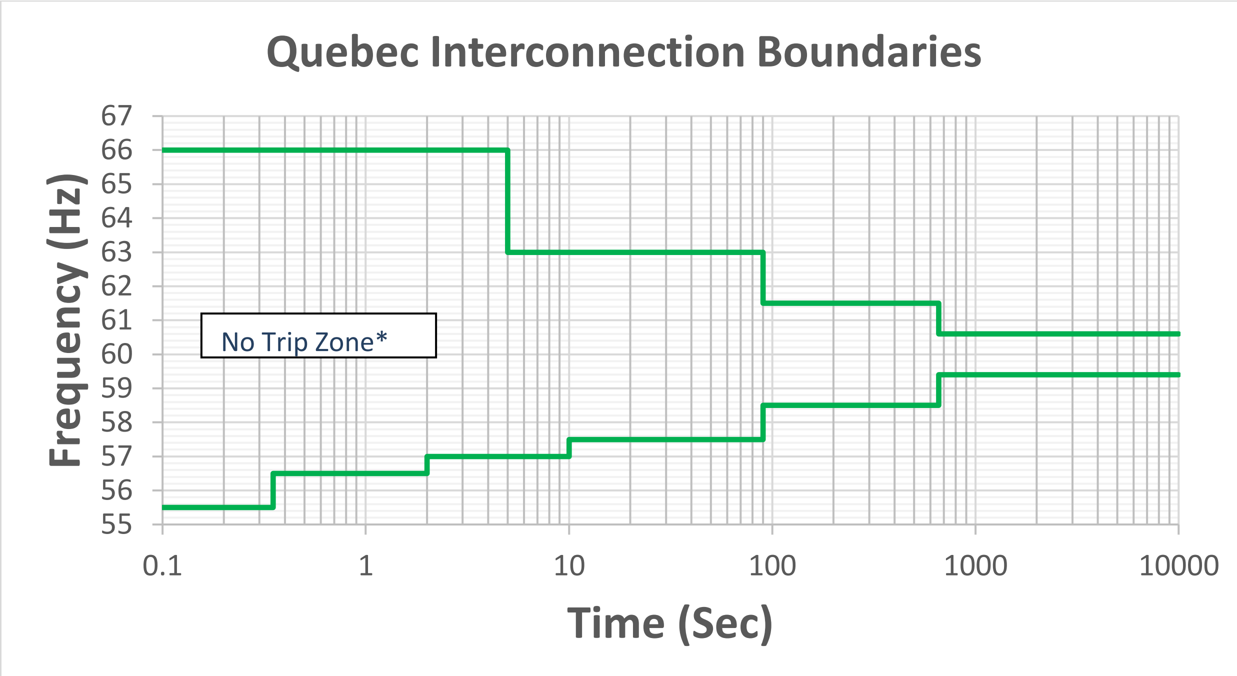


Figure ~~3~~1.5

**** 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[11]	<55.5	Instantaneous[11]
≥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~~1.6

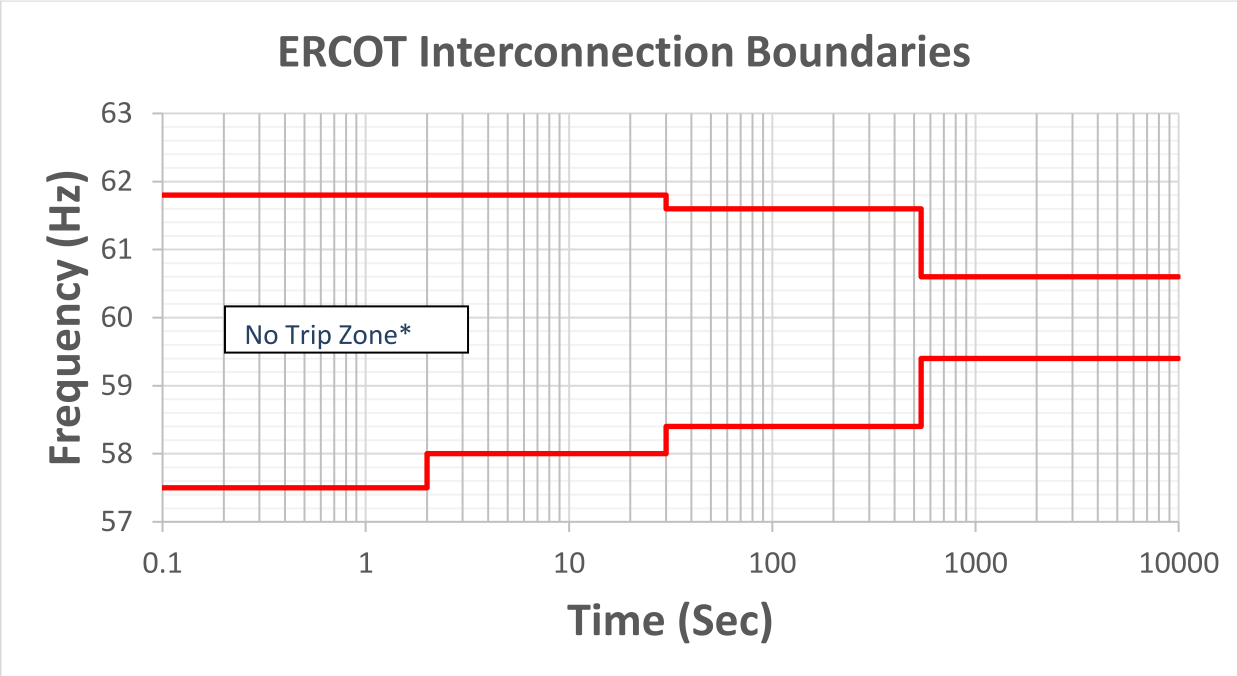


Figure ~~4~~1.7

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[11]	≤57.5	Instantaneous[11]
≥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~~1.8

PRC-024 — Attachment 2

(Voltage No-Trip Boundaries – Eastern, Western, and ERCOT Interconnections)

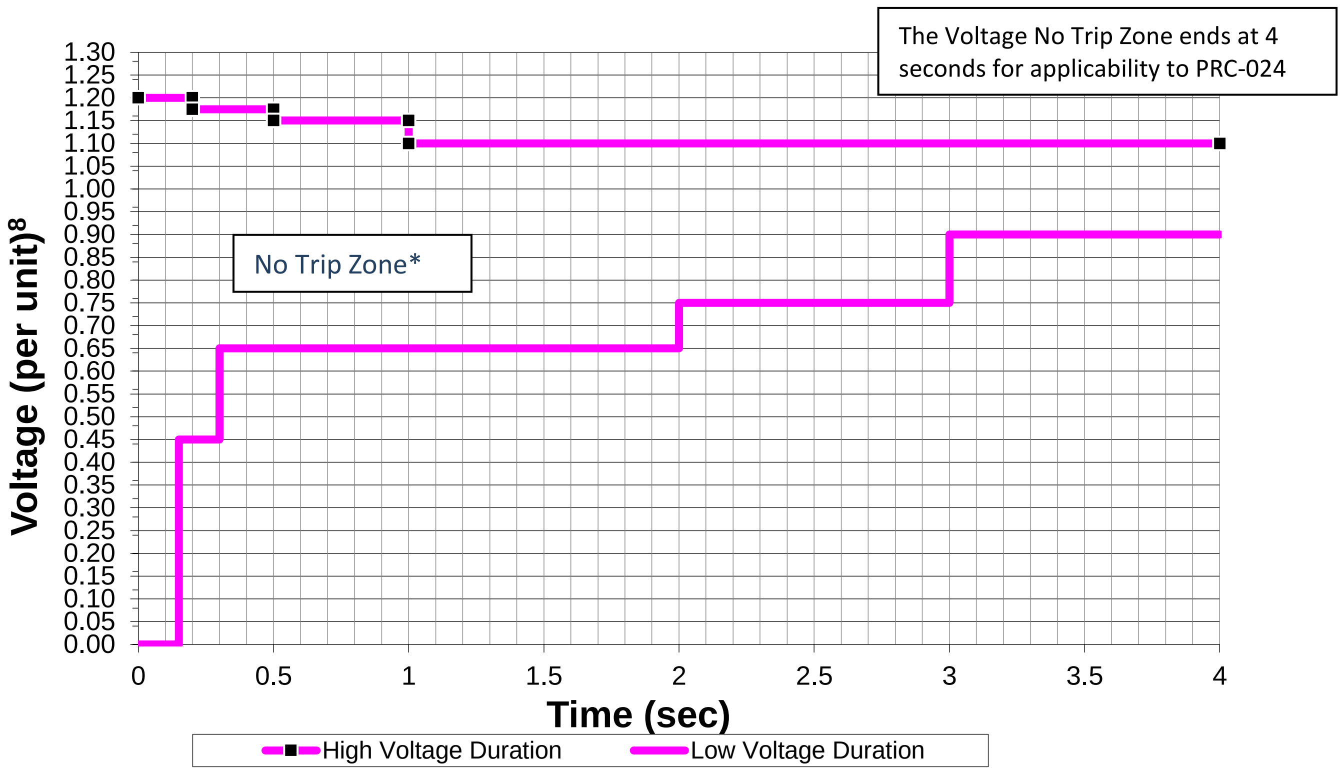


Figure 2.1

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

Voltage Boundary Data Points

High Voltage Duration		Low Voltage Duration	
Voltage (per unit)	**Minimum Time (sec)**	**Voltage (per unit)**	**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~~2.2

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

Attachment 2A: Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections

Boundary Details:

1. Unless otherwise specified by the Transmission Planner, the per unit voltage base for these boundaries is the nominal transmission system voltage (e.g., 100 kV, 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 400 kV, 500 kV, 765 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 boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase per unit voltage.
5. For applicability to PRC-024, the "no trip zone" ends at 4 seconds.

Evaluating Protection Settings:

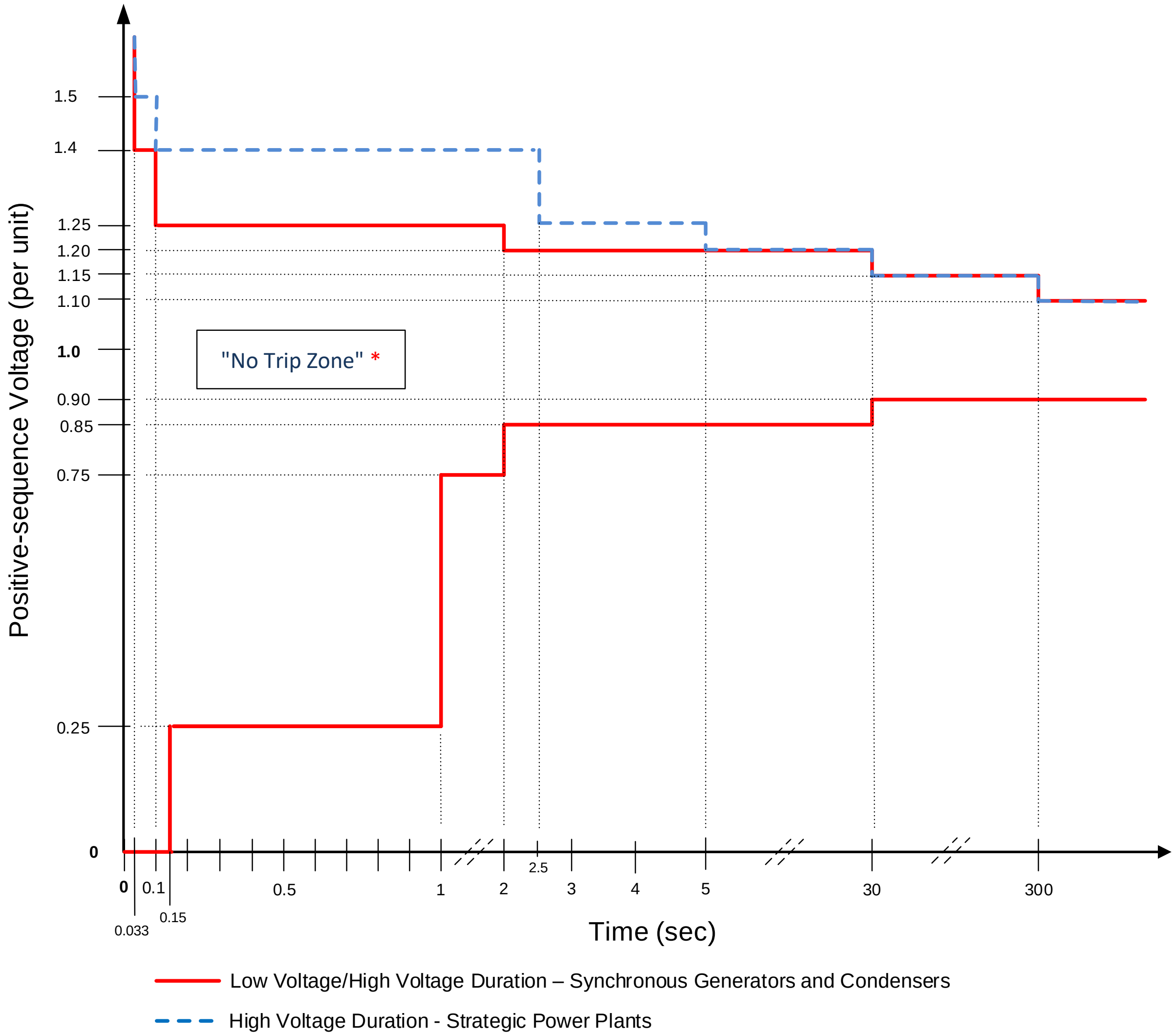
The voltage values in the Attachment 2 voltage boundaries are voltages at the high~~-~~-side of the GSU/MPT. For ~~generating~~ resources with multiple stages of step up to reach interconnecting voltage, this is the high~~-~~-side of the transformer with a low side below 100kV and a high~~-~~-side 100kV 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 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.

PRC-024— Attachment 2B~~a~~

(Voltage No-Trip Boundaries – Quebec Interconnection)


Positive-sequence Voltage (per unit)
1.5
1.4
1.25
1.20
1.15
1.10
1.0
0.90
0.85
0.75
0.25
0
"No Trip Zone" *
0
0.1
0.033
0.15
0.5
1
2
2.5
3
4
5
30
300
Time (sec)
Low Voltage/High Voltage Duration – Synchronous Generators and Condensers
High Voltage Duration - Strategic Power Plants

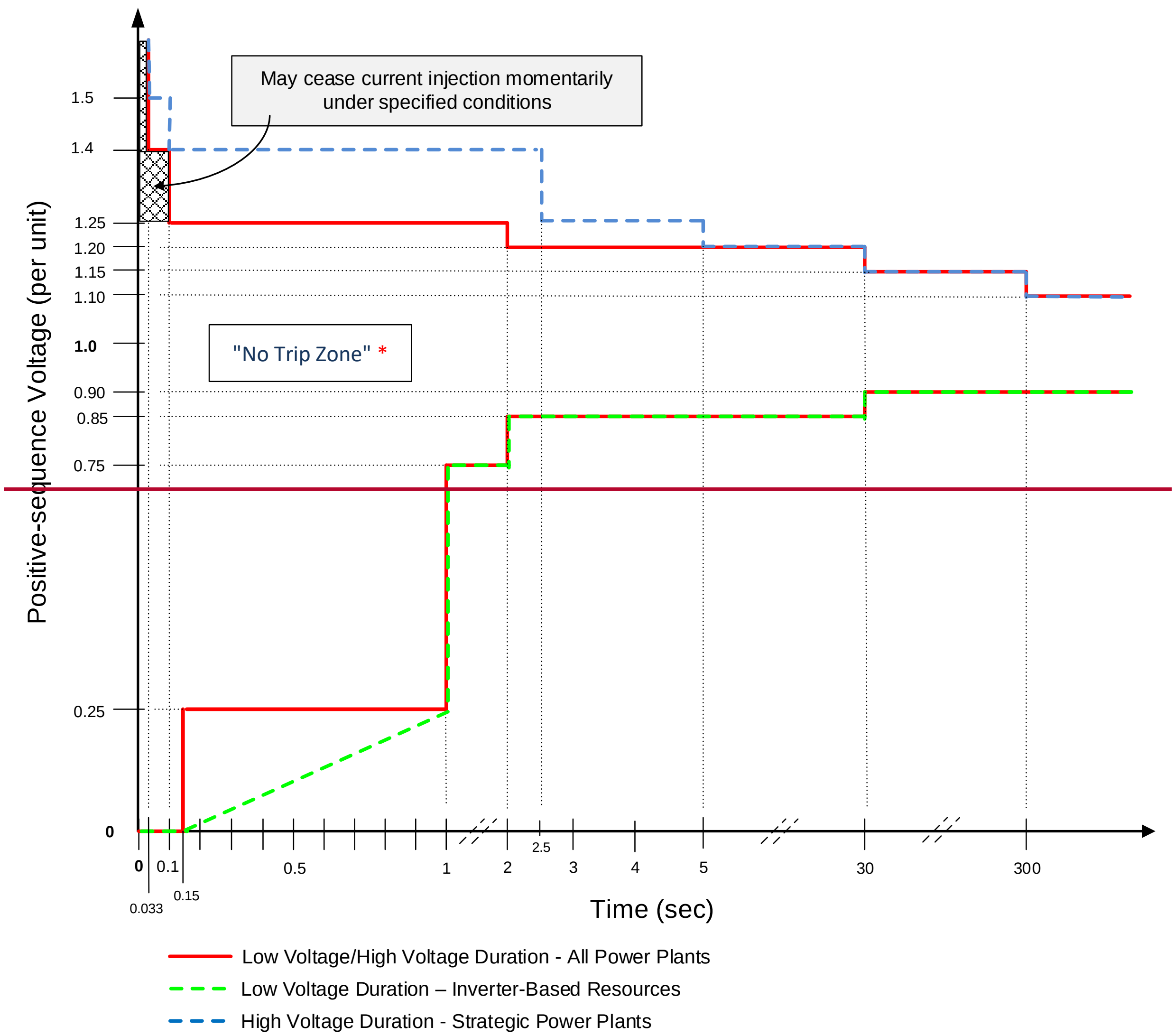


Figure 1

** 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~~ Synchronous Generators and Condensers		High Voltage Duration for strategic[1] Power Plants	
Voltage (per unit)	Minimum Time (sec)	Voltage (per unit)	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~~Synchronous Generators and Condensers		~~Low Voltage Duration for Inverter-Based Resources~~	
Voltage (per unit)	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 2C~~a~~: 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 2B~~a~~ 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.

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

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023

Anticipated Actions	Date
25-day formal comment period with initial ballot	March 27 - April 22, 2024
15-day formal comment period and additional ballot	May 20 - June 4, 2024
15-day formal comment period and additional ballot	July 1 - 16, 2024
Final Ballot	July 18 - 24, 2024
Board adoption	August 14, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Continuous Operating Region – The range of voltages, measured at the high-side of the main power transformer, that are ≥ 0.9 per unit and ≤ 1.1 per unit.

Mandatory Operating Region – The range of voltages, measured at the high-side of the main power transformer, that are > 0.1 per unit and < 0.9 per unit – or – > 1.1 and ≤ 1.2 per unit.

Permissive Operating Region – The range of voltages, measured at the high-side of the main power transformer, that is ≤ 0.1 per unit.

A. Introduction

1. **Title:** **Frequency and Voltage Ride-through Requirements for Inverter-Based Generating Resources**
2. **Number:** **PRC-029-1**
3. **Purpose:** To ensure that Inverter-Based Resources (IBRs) remain connected and perform operationally as expected to support of the Bulk Power System (BPS) during and after defined frequency and voltage excursions.
4. **Applicability:**

   4.1 Functional Entities:

   4.1.1. Generator Owner

   4.1.2. Transmission Owner[1]

   4.2 Facilities: For purposes of this standard, the term "applicable Inverter-Based Resource" or "applicable Inverter-Based Resources" refers to the following:

   4.2.1. BPS IBRs

   4.2.2. IBR Registration Criteria

5. **Effective Date:** See Implementation Plan for Project 2020-02 – PRC-029-1

[1] For owners of Voltage Source Converter – High-voltage Direct Current (VSC-HVDC) transmission facilities that are dedicated connections for IBR to the BPS

B. Requirements and Measures

R1. Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that each IBR remains electrically connected and continues to exchange current in accordance with the no-trip zones and operation regions as specified in **Attachment 1** unless needed to clear a fault or a documented equipment limitation exists in accordance with **Requirement R6**. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

M1. Each Generator Owner and Transmission Owner shall have evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in **Requirement R1**.

R2. Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that during a System disturbance, each IBR's voltage performance adheres to the following, unless a documented equipment limitation exists in accordance with **Requirement R6**. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

2.1. While the voltage at the high-side of the main power transformer remains within the Continuous Operation Region as specified in **Attachment 1**, each IBR shall:

2.1.1 Continue to deliver the pre-disturbance level of active power or available active power, whichever is less, and continue to deliver active power and reactive power up to its apparent power limit.

2.1.2 If the IBR cannot deliver both active and reactive power due to a current or apparent power limit, when the applicable voltage is below 95% and still within the Continuous Operation Region, then preference shall be given to active or reactive power according to requirements specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.2. While voltage at the high-side of the main power transformer is within the Mandatory Operation Region as specified in **Attachment 1**, each IBR shall:

2.2.1 Exchange current, up to the maximum capability while maintaining automatic voltage regulation, on the affected phases during both symmetrical and asymmetrical voltage disturbances.

2.2.2 Adjust reactive current injection at the high-side of the main power transformer so that the magnitude of the reactive current responds to changes in voltage at the high-side of the main power transformer in accordance with default reactive prioritization unless the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specifies a certain magnitude of reactive power response to voltage changes or specifies active power priority instead of reactive power priority.

2.3. The IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable **Attachment 1** Table 1 or Table 2 no-trip zone voltage thresholds and time durations in its response from Mandatory or Permissive Operation Regions to the Continuous Operating Region.

2.4. Each IBR shall restore active power output to the pre-disturbance or available level within 1.0 second when the voltage at the high-side of the main power transformer returns to the Continuous Operation Region from the Mandatory Operation Region or Permissive Operation Region (including operation in current block mode) as specified in **Attachment 1**, unless the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specifies a lower post-disturbance active power level requirement or specifies a different post-disturbance active power restoration time.

2.5. Each IBR shall only trip to prevent equipment damage, when the voltage at the high-side of the main power transformer is outside of the no-trip zone as specified in **Attachment 1**.

M2. Each Generator Owner and Transmission Owner shall have evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to performance requirements, as specified in **Requirement R2**, during each System disturbance which has occurred within the associated Planning Coordinator(s) area(s).

R3. Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that during a transient overvoltage as a result of a switching event whereby instantaneous voltage at the high-side of the main power transformer exceeds 1.2 per unit, each IBR shall either: *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

- Remain electrically connected and continue to exchange current in accordance with instantaneous transient overvoltage levels and durations specified in **Attachment 2**; or
- Remain electrically connected in current block mode in accordance with instantaneous transient overvoltage levels and durations specified in **Attachment 2**, and restart current exchange within 5 cycles of the instantaneous voltage falling below (and remaining below) 1.2 per unit.

M3. Each Generator Owner and Transmission Owner shall have evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to performance requirements, as specified in Requirement R3, during each transient overvoltage period which has occurred within the associated Planning Coordinator(s) area(s).

R4. Each Generator Owner or Transmission Owner of an applicable IBR shall ensure each IBR remains electrically connected and continues to exchange current during a frequency excursion event whereby the frequency remains within the “no trip zone” according to **Attachment 3** and the absolute rate of change of frequency (ROCOF)[2]

[2] Rate of change of frequency (ROCOF) is calculated as the average rate of change for multiple calculated system frequencies for a time period of greater than or equal to 0.1 second. ROCOF is not calculated during the fault occurrence and clearance.

magnitude is less than or equal to 5 Hz/second. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

M4. Each Generator Owner and Transmission Owner shall have evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in Requirement R4, during each frequency excursion event which has occurred within the associated Planning Coordinator(s) area(s).

R5. Each Generator Owner or Transmission Owner of an applicable IBR shall ensure each IBR remains electrically connected and continues to exchange current during instantaneous positive sequence voltage phase angle changes that are initiated by non-fault switching events on the transmission system and are changes of less than 25 electrical degrees at the high-side of the main power transformer. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

5.1. When the instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer and is initiated by a non-fault switching event on the transmission system, the IBR may trip, but shall only trip to prevent equipment damage.

M5. Each Generator Owner and Transmission Owner shall have evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in Requirement R5, during instantaneous positive sequence voltage phase angle changes that are changes of less than 25 electrical degrees at the high-side of the main power transformer and that such changes are not initiated by non-fault switching events.

R6. Each Generator Owner and Transmission Owner with a documented equipment limitation that would prevent an applicable IBR that is in-service by the effective date of this standard from meeting voltage ride-through requirements as detailed in Requirements R1 and R2 shall communicate each equipment limitation to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s). *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1. Each Generator Owner and Transmission Owner shall include in its documentation:

6.1.1 Identifying information of the IBR (name, facility #, other)

6.1.2 Which aspects of voltage ride-through requirements that the IBR would be unable to meet

6.1.3 Identify the specific piece(s) of equipment causing the limitation

6.1.4 Information regarding any plans to repair or replace the limiting equipment that would remove the limitation (such as estimated date of repair/replacement)

6.2. Each Generator Owner and Transmission Owner with a previously communicated equipment limitation that repairs or replaces the equipment causing the limitation shall document and communicate such equipment change to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s) within 30 days of the equipment change.

M6. Each Generator Owner and Transmission Owner shall have evidence of equipment limitations, as specified in Requirement R6, documented prior to the effective date of PRC-029-1. Each Generator Owner and Transmission Owner with changes to equipment shall have evidence of communication to each associated Planning Coordinator, Transmission Planner, and Reliability Coordinator. Acceptable types of evidence may include, but are not limited to, meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence.

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.

1.2. Evidence Retention: 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.

- Each Generator Owner and Transmission Owner shall retain evidence with each requirement in this standard for five calendar years.

1.3. Compliance Monitoring and Enforcement 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.

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 or Transmission Owner failed to demonstrate each applicable IBR remains electrically connected and continued to exchange current in accordance with Attachment 1, unless needed to clear a fault, in accordance with Requirement R1.
R2.	N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable IBR adhered to performance requirements during each System disturbance, as specified in Requirement R2.
R3.	N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable IBR adhered to performance requirements during each transient overvoltage period as specified in Requirement R3.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R4.	N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable IBR adhered to performance requirements during each frequency excursion event, as specified in Requirement R4.
R5.	N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable IBR adhered to performance requirements during each instantaneous positive sequence voltage phase angle change of less than 25 electrical degrees, as specified in Requirement R5.
R6.	The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator, Transmission Planner, and Reliability	The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator, Transmission Planner, and Reliability	The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator, Transmission Planner, and Reliability	The Generator Owner or Transmission Owner failed to document evidence of equipment limitations consistent with Requirement R6 and prior to the effective date of PRC-029-1 Requirement R6. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Coordinator more than 30 calendar days but less than or equal to 60 calendar days after the change to the equipment.	Coordinator more than 60 calendar days but less than or equal to 90 calendar days after the change to the equipment.	Coordinator more than 90 calendar days but less than or equal to 120 calendar days after the change to the equipment.	The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator, Transmission Planner, and Reliability Coordinator more than 120 calendar days after the change to the equipment.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan .

Version History

Version	Date	Action	Change Tracking
Initial Draft	3/27/24	DRAFT	

Attachment 1: Voltage Ride-Through Criteria

Table 1: Voltage Ride-Through Requirements for AC-Connected Wind IBR

Voltage (per unit)	Minimum Ride-Through Time (sec)
≥1.200	N/A
≥1.1	1.0
≥1.05	1800
< 0.90	3.00
< 0.70	2.50
< 0.50	1.20
< 0.25	0.16
< 0.10	0.16

Table 2: Voltage Ride-Through Requirements for All Other IBR

Voltage (per unit)	Minimum Ride-Through Time (sec)
≥1.200	N/A
≥1.1	1.0
≥1.05	1800
< 0.90	6.00
< 0.70	3.00
< 0.50	1.20
< 0.25	0.32
< 0.10	0.32

1. Table 1 applies to applicable wind IBR unless connected via a dedicated VSC-HVDC transmission facility.
2. Table 2 applies to all other IBR types not covered in Table 1; including, but not limited to, the following IBR:
    a. Isolated IBR, regardless of their energy resource, interconnecting via a dedicated VSC-HVDC transmission facility.
    b. Other IBR plants or hybrid plants consisting of photovoltaic (PV) and ESS.

3. In the case of hybrid IBR consisting of wind and various other IBR technologies, the applicable table shall be based on direction by the Transmission Planner.
4. The voltage base for per unit calculation is the nominal phase-to-ground or phase-to-phase transmission system voltage unless otherwise defined by the Planning Coordinator or Transmission Planner.
5. The applicable voltage for Tables 1 and 2 is identified as the voltage max/min of phase to neutral or phase to phase fundamental root mean square (RMS) voltage at the high side of the MPT.
6. Tables 1 and 2 are only applicable when the frequency is within the no trip zone as specified in Table 3 of Attachment 3.
7. At any given voltage value, each IBR shall not trip until the time duration at that voltage exceeds the specified minimum ride-through time duration. If the voltage is continuously varying over time, it is necessary to add the duration within each band of Tables 1 and 2 over the 10-second time period to determine compliance.
8. The specified duration of the Mandatory Operation Regions and the Permissive Operation Regions in Tables 1 and 2 is cumulative over one or more disturbances within a 10 second time period.
9. The IBR may trip for more than four deviations of the applicable voltage at the high-side of the main power transformer outside of the Continuous Operation Region within any 10 second time period.
10. If the positive sequence voltage at the high-side of the main power transformer enters the Permissive Operation Region, an IBR may operate in current block mode if necessary to protect the equipment.

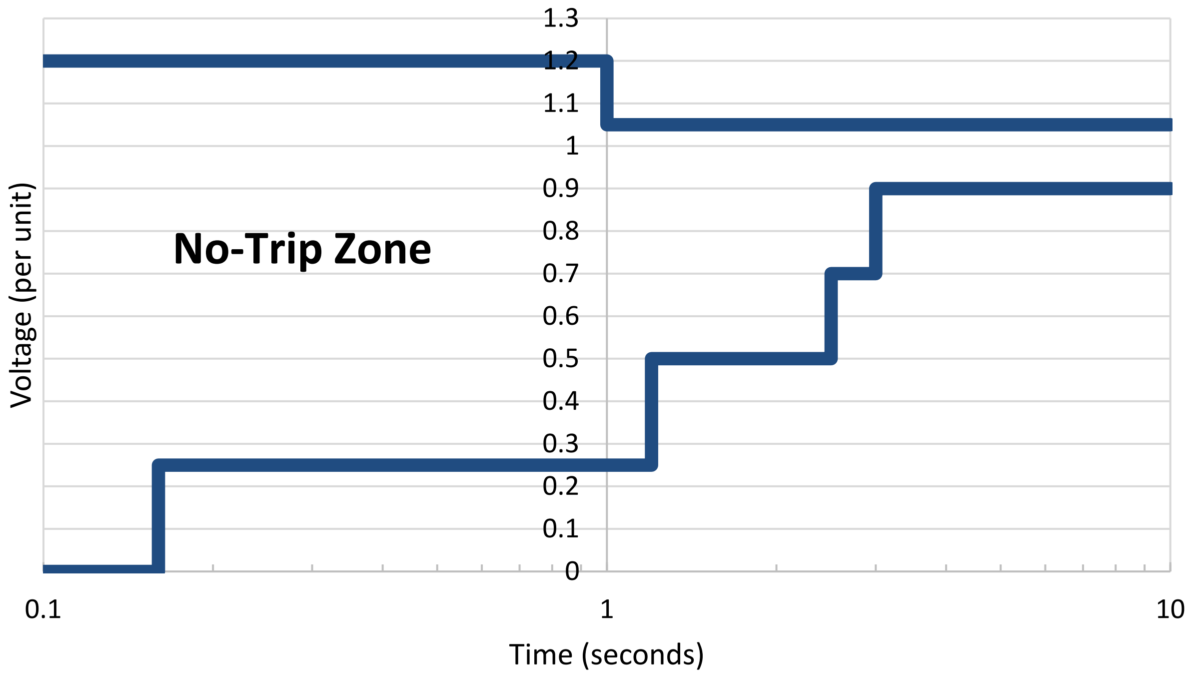


Figure 1: Voltage Ride-Through Requirements for AC-Connected Wind IBR

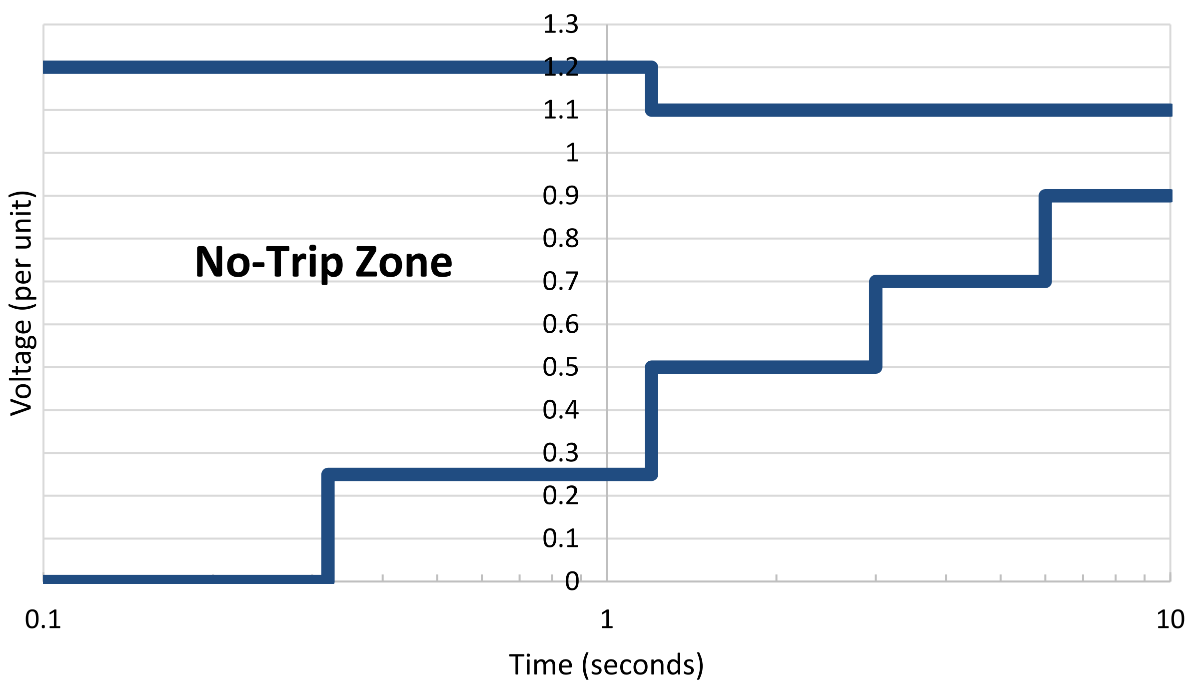


Figure 2: Voltage Ride-Through Requirements for All Other IBR

Attachment 2: Transient Overvoltage Ride-Through Criteria

Table 3: Transient Overvoltage Ride-Through Criteria

Voltage (per unit) at the high side of the MPT	Minimum Ride-Through Time (millisec)
> 1.8	May trip
> 1.7	0.2
> 1.6	1.0
> 1.4	3.0
> 1.2	15.0

1. The voltage base for per unit calculation is the nominal instantaneous phase-to-ground or phase-to-phase voltage at the high side of the MPT unless otherwise defined by the Planning Coordinator or Transmission Planner.
2. If surge protection devices are installed within the plant, the per unit voltage refers to the residual voltage with the surge arresters applied.
3. Each IBR shall not trip unless the cumulative time of one or more instances over a 1-minute time window in which the instantaneous voltage exceeds the respective voltage threshold and the minimum ride-through time.

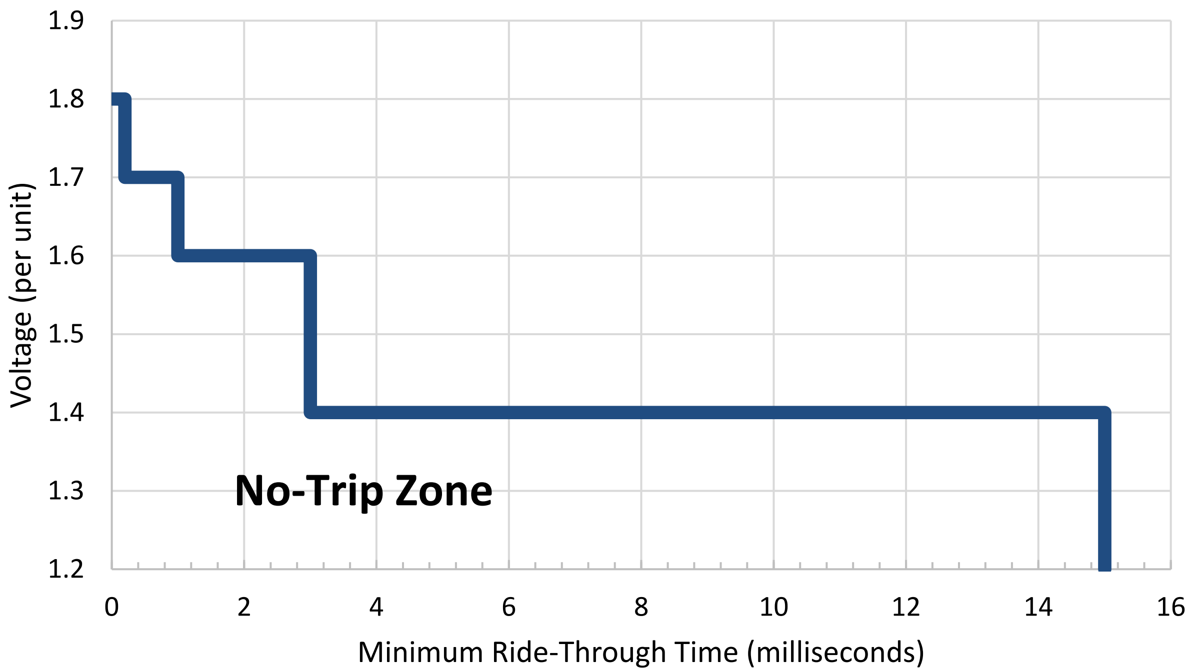


Figure 3: Transient Overvoltage Ride-Through Criteria

Attachment 3: Frequency Ride-Through Criteria

Table 4: Frequency Ride-Through Capability Requirements

Averaged System Frequency (Hz)	Minimum Ride-Through Time (sec)
≥64	May trip
≥61.8	6
> 61.5	299
> 61.2	660
< 58.8	660
< 58.5	299
< 57.0	6
< 56	May trip

1. Measurements are taken at the high-side of the main power transformer for each phase (phase to neutral).
2. Measurements are averaged over a set time period (such as 3-6 cycles) to calculate averaged system frequency at the high-side of the main power transformer.
3. Instantaneous or single points of measurement may not be used in the determination of control settings.
4. At any given frequency values, each IBR shall not trip until the time duration at that frequency exceeds the specified minimum ride-through time duration.
5. The specified durations of Table 4 are cumulative over one or more disturbances within a 15-minute time period.

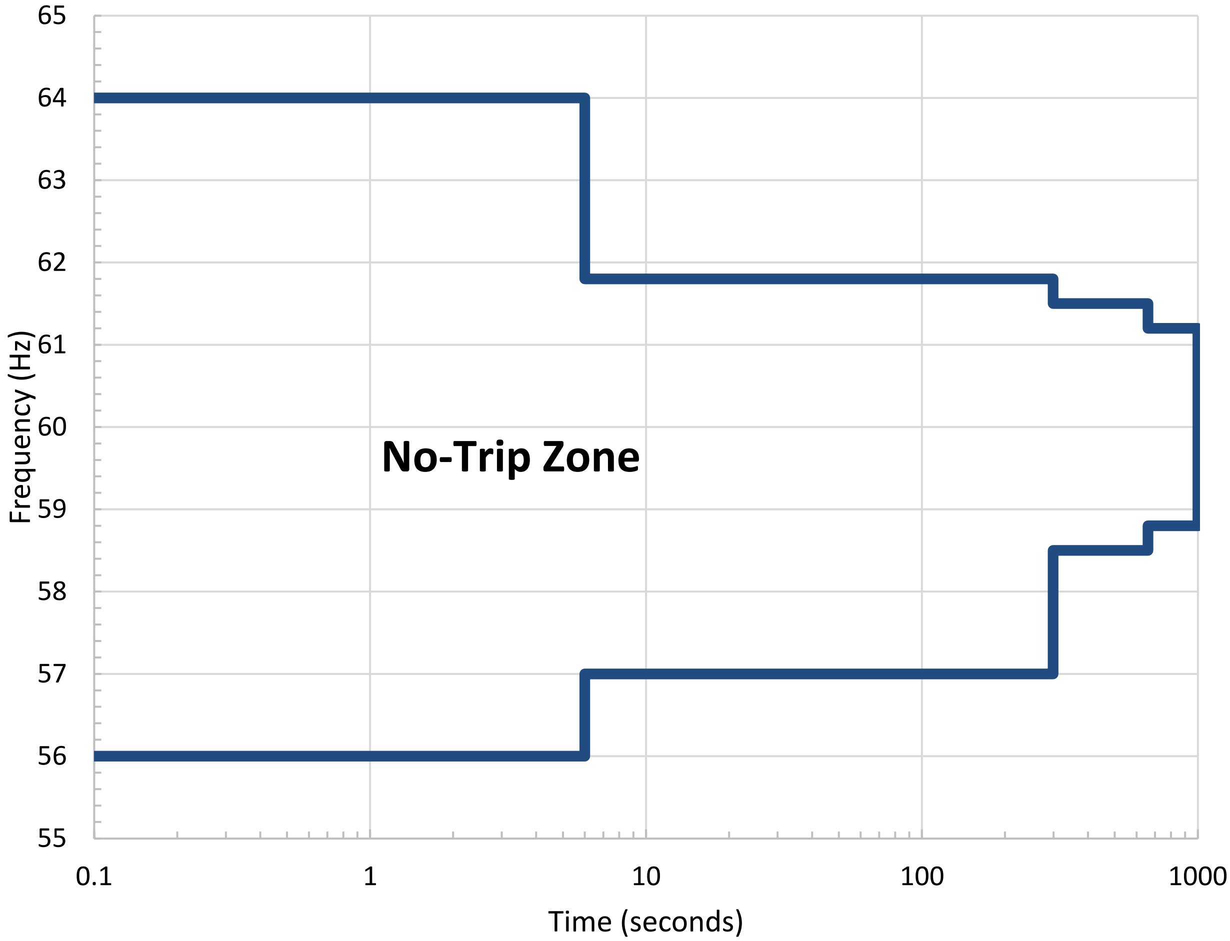


Figure 4: PRC-029 Frequency Envelopes

Implementation Plan

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
Reliability Standards PRC-024-4 and PRC-029-1

Applicable Standard(s)

- PRC-024-4 Frequency and Voltage Protection Settings for Synchronous Generators and Synchronous Condensers
- PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Generating Resources

Requested Retirement(s)

- PRC-024-3 Frequency and Voltage Protection Settings for Generating Resources

Prerequisite Standard(s)

- PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

Proposed Definition(s)

- None

Applicable Entities

- See subject Reliability Standards.

Background

The purpose of Project 2020-02 is to modify Reliability Standard PRC-024-3 or replace it with a performance-based ride-through standard that ensures generators remain connected to the Bulk-Power System (BPS) during system disturbances. Specifically, the project focuses on using disturbance monitoring data to substantiate inverter-based resource (IBR) ride-through performance during grid disturbances. The project also ensures associated generators that fail to ride-through system events are addressed with a corrective action plan (if possible) and reported to necessary entities for situational awareness.

The purpose for this project is based on the culmination of multiple analyses conducted by the ERO Enterprise regarding widespread inverter-based resource tripping events. Furthermore, the NERC Inverter-Based Resource Performance Subcommittee[1] has developed comprehensive

[1] See documents at the NERC IRPS website: https://www.nerc.com/comm/RSTC/Pages/IRPS.aspx and the previous Inverter-Based Resource Performance Working Group website https://www.nerc.com/comm/RSTC/Pages/IRPWG.aspx

recommendations for improved performance of inverter-based resources, including the recommendation to develop comprehensive ride-through requirements.

In October 2023, FERC issued Order No. 901[2] which directs the development of new or modified Reliability Standards that include new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. In January 2024, NERC submitted a filing to FERC outlining a comprehensive work plan to address the directives within Order No. 901.[3] Within the work plan, NERC identified three active Standards Development projects that would need to be filed for regulatory approval with FERC by November 4, 2024. These projects include **2020-02 Modifications to PRC-024 (Generator Ride-through)**[4], **2021-04 Modifications to PRC-002-2**[5], and **2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues**[6].

Project 2020-02

Proposed Reliability Standard PRC-029-1 is a new Reliability Standard that includes ride-through requirements and performance requirements for IBRs. The scope of this project was adjusted to align with associated regulatory directives from FERC Order No. 901 and the scope of the other projects related to “Milestone 2” of the NERC work plan. The components of this project’s Standard Authorization Request (SAR) that related to the inclusions of new data recording requirements are covered in Project 2021-04 and the proposed new PRC-028-1 Reliability Standard. Components of this project’s SAR that relate to analytics and corrective actions plans are covered in Project 2023-02 and the proposed new PRC-030-1 Reliability Standard.

PRC-029-1 includes requirements for Generator Owner and Transmission Owner IBR to continue to inject current and perform frequency support during a BPS disturbance. The standard also specifically requires Generator Owner and Transmission Owner IBR to prohibit momentary cessation in the no-trip zone during disturbances.

PRC-024-4 includes modifications to revise applicable facility types to remove IBR and to include synchronous condensers.

[2] See FERC Order 901, Docket No. RM22-12-000; https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false; October 19, 2023

[3] See INFORMATIONAL FILING OF THE NORTH AMERICAN RELIABILITY CORPORATION REGARDING THE DEVELOPMENT OF RELIABILITY STANDARDS RESPONSIVE TO ORDER NO. 901 https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/NERC%20Compliance%20Filing%20Order%20No%20901%20Work%20Plan_packaged%20-%20public%20label.pdf; January 17, 2024

[4] See NERC Standards Development Project page for Project 2002-02; https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx

[5] See NERC Standards Development Project page for Project 2021-04; https://www.nerc.com/pa/Stand/Pages/Project-2021-04-Modifications-to-PRC-002-2.aspx

[6] See NERC Standards Development Project page for Project 2023-02; https://www.nerc.com/pa/Stand/Pages/Project-2023-02-Performance-of-IBRs.aspx

General Considerations

The ERO Enterprise acknowledges that there are IBRs currently in operation and unable to meet voltage ride-through requirements due to their inability to modify their coordinated protection and control settings. Consistent with FERC Order No. 901, a limited and documented exemption process for those IBR is appropriate and included within this Implementation Plan. Other NERC Standards Development projects will be pursued to address ongoing identification and mitigation of any potential reliability impacts to the BPS for such exemptions.

Effective Date and Phased-in Compliance Dates

The effective dates for the proposed Reliability Standards are provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance dates for those particular sections represent the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

PRC-024-4

Where approval by an applicable governmental authority is required, Reliability Standard PRC-024-4 shall become effective on the first day of the first calendar quarter that is 6 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the Reliability Standard PRC-024-4 shall become effective on the first day of the first calendar quarter that is 6 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

PRC-029-1

Where approval by an applicable governmental authority is required, Reliability Standard PRC-029-1 shall become effective on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the Reliability Standard PRC-029-1 shall become effective on the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Date for PRC-029-1 - Requirement R6

Entities shall not be required to comply with Requirement R6 until six months after the effective date of Reliability Standard PRC-029-1. This compliance date is intended to assure equipment limitations have additional time to complete the equipment limitation process as outlined below.

Retirement Date

PRC-024-3

Reliability Standard PRC-024-3 shall be retired immediately prior to the effective date of Reliability Standards PRC-024-04 and PRC-029-1 in the particular jurisdiction in which the revised standard is becoming effective.

Equipment Limitations and Process for Requirement R6

Consistent with FERC Order No. 901, a limited and documented exemption for some legacy IBR with certain documented equipment limitations are acceptable. Per the Order, these IBRs are

> "…typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements."[7]

To assure compliance with Requirement R6 and alignment with FERC Order No. 901, only those IBR that are in operation as of the effective date of PRC-029-1 may be considered for potential exemption. Further, only those IBR that are unable to meet voltage ride-through requirements due to their inability to modify their coordinated protection and control settings may be considered for potential exemption.

Generator Owners with IBR that meet these criteria for equipment limitations must identify which of those IBR will be unable to meet voltage ride-through requirements, as described in Requirement R6. For each identified IBR, the associated Generator Owner must document:

- Identifying information of the IBR (name, facility #, other)
- Which aspects of voltage ride-through requirements that the IBR would be unable to meet
- Information regarding the limiting equipment
- Information regarding any plans to repair or replace the limiting equipment that would remove the limitation (such as estimated date of repair/replacement)

For each identified IBR, the associated Generator Owner must communicate the documented information listed above to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s), per the Requirement R6 no later than the effective date of Requirement R6.

[7] Order No. 901 at p. 193.

Unofficial Comment Form

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

Do not use this form for submitting comments. Use the [Standards Balloting and Commenting System (SBS)] to submit comments on **Project 2020-02 Modifications to PRC-024 (Generator Ride-through)** by **8 p.m. Eastern, Monday, April 22, 2024.**

Additional information is available on the [project page]. If you have questions, contact Manager of Standards Development, [Jamie Calderon] (via email), or at 404-960-0568.

Background Information

The goal of Project 2020-02 is to mitigate the recent and ongoing disturbance ride-through performance issues identified across multiple Interconnections and numbers of disturbances analyzed by NERC and the Regions. These issues have been associated with Inverter-Based Resources (IBR) with many causes of their tripping or cessation unrelated to voltage and frequency protection settings requirements in the currently effective version of PRC-024, PRC-024-3. Proposed Reliability Standard PRC-024-4 includes revisions to limit its applicability to synchronous generators and synchronous condensers only and remains as a protection-based standard. A new standard, PRC-029-1, is proposed as a true disturbance ride-through Reliability Standard with applicability to inverter-based resources..

In October 2023, FERC issued Order No. 901, which directed NERC to develop new or modified existing Reliability Standards that include new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. Project 2020-02 was one of three projects identified by NERC that must be completed and filed with FERC by November 4, 2024 to address Order No. 901 directives. At their December 2023 meeting, the Standards Committee approved a waiver for Project 2020-02, allowing formal comment periods to be reduced from 45 days to 25 calendar days, ballot pools reduced from 30 days to as few as 10 days, and final ballot periods to be reduced from 10 days to as few as 5 calendar days.

Questions

1. Do you agree with the need for creating a new Standard (PRC-029-1) to address gaps the Inverter-Based Resource Performance Subcommittee (IRPSC) identified within the PRC-024-3 Project 2020-02 SAR and to address the expectations of FERC Order No. 901?

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree that the language within PRC-029-1 requirements R1, R2, and R6 regarding IBR plant-level performance during grid voltage disturbances is clear?

☐ Yes
☐ No

Comments:

3. Do you agree with the drafting team's proposals for including IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in PRC-029-1 Requirements R3, R4, and R5?

☐ Yes
☐ No

Comments:

4. Provide any additional comments for the Drafting Team to consider, if desired.

Comments:

Technical Rationale

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

PRC-024-4 – Frequency and Voltage Protection Settings for Synchronous Generators and Synchronous Condensers

General Rationale

The drafting team proposes to modify PRC-024-3 to retain the Reliability Standard as a protection-based standard with applicability to only synchronous generators and synchronous condensers. This proposal is a consequence of both the different natures of synchronous and inverter-based generation resources and several recent events exhibiting significant IBR ride-through deficiencies. The behavior of rotating synchronous generators during faults and other disturbances on the transmission system is well established and understood in comparison to IBR generation. The disturbance ride-through vulnerabilities of synchronous generators are pole slipping instability and undervoltage dropout of critical plant auxiliary equipment, leading to tripping of a generator. Pole slipping can be managed by active power dispatch and system condition constraints, and is outside the scope of PRC-024-3. Undervoltage dropout of critical auxiliary equipment is also outside the scope of PRC-024-3 because of complexities associated with auxiliary systems and how such equipment behaves under low voltage conditions.

The Project 2020-02 Standard Authorization Request (SAR) notes that auxiliary equipment has not posed a ride-through risk and the SAR specifically excludes modifications in PRC-024-3 for auxiliary equipment. Over-frequency protection, under-frequency protection, and voltage protection may or may not be applied to synchronous generating units. If applied however, settings should be coordinated between the needs of generating unit protection, reasonable expected excursions of system frequency and voltage in a straightforward fashion, e.g., as no-trip zones within PRC-024-3 attachments, as well as the coordination of generating unit capabilities, voltage regulating controls, and protection within PRC-019-2. Excitation and governing controls affect synchronous generator ride-through behavior to some degree but because of progressive improvement, standardization, and level of maturity of these controls, they are rarely if ever cause unnecessary tripping during disturbances.

In addition, there are other existing NERC standards to prevent unnecessary tripping of the generators during a system disturbance such as PRC-025-2 “Generator Relay Loadability”, and PRC-026-2 “Relay Performance During Stable Power Swings”. For these reasons, there is no need to impose actual disturbance ride-through requirements on synchronous units and only include restrictions for frequency and voltage protection setting ranges as maintained in PCR-024-4.

Rationale for Applicability Section (4.0)

Functional Entities (4.1)

The functional entity responsible for setting frequency, voltage, and volts per hertz protection for synchronous generators and synchronous condensers is the Generator Owner (GO) and Transmission

Owner (TO). Planning Coordinators (PC) are also retained as applicable entities but are only in the Quebec Interconnection. Modifications are proposed in PRC-024-4 to expand functional entity applicability to includes those Transmission Owners that apply protection, as listed in new Facility applicability section 4.2.2.

Facilities (4.2)

Applicability Facilities subparts in Section 4.1.1 were modified to restrict PRC-024-4 to synchronous generators. Section 4.2.2 was added as new subparts to identify which synchronous condensers and equipment.

Rationale for Requirements R1 through R4

Modifications were made to Requirements R1, R2, R3, and R4 to include the Transmission Owner as an functional entity applicable to each requirement.

Modifications were made to Requirements R1, R2, R3, and R4 to include language for synchronous condensers and to remove language that relates to inverter-based resource functionality (i.e., “cease injecting current”).

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Technical Rationale

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

PRC-029-1 – Frequency and Voltage Ride-Through Requirements for Inverter-Based Generating Resources

General Rationale

The drafting team has created a new Reliability Standard (PRC-029-1) to address inverter-based resource (IBR) disturbance ride-through performance criteria. This proposal is a consequence of both the different natures of synchronous and inverter-based generation resources and several recent events exhibiting significant IBR ride-through deficiencies. The proposed PRC-029-1 coincides with ride-through requirements of IEEE 2800 but is structured to follow language from FERC Order No. 901, which states that "NERC has the discretion to consider during its standards development process whether and how to reference IEEE standards in the new or modified Reliability Standards."[1]

The lack of standardization of IBR technology (equipment/controller behavior) has created reliability challenges associated with the interconnection of IBR facilities to the power grid. The nature of the fast switching of power electronics of IBR generation and the electronic interface to the transmission system is such that disturbance ride-through behavior is largely determined by manufacturer-specific equipment and controls system designs. These controls may be programmed but also have more restrictive limits on current, both in magnitude and duration. IBR responses to grid disturbances are highly controlled and managed by using fast switching of power electronics devices dependent upon manufacturer specific control system design that can be programmed in many ways and with various and concurrent ride--through performance objectives. Rather than attempting to restrict the myriad of control approaches, protections, and settings, it is more straightforward to require ride-through during defined frequency and voltage excursions.

In contrast to synchronous generation, the need for IBR ride-through requirements has been heightened by recent events during which IBRs have not met PRC-024-3 frequency and voltage ride-through expectations, often due to controls and protection only indirectly associated with the system voltage and frequency excursions. In addition to ride-through, there is the question of what IBRs should be doing as they ride-through. IBR responses to system disturbances can be beneficial or detrimental to both their own ride-through and system reliability, often depending on adjustable control settings. Thus, it is essential to set expectations on performance during ride-through as well as ride-through capability.

IBR do not provide inertia or short circuit contributions, unlike synchronous machines. The drafting team thinks that IBR should compensate for their lack of inertia and short circuit contributions with wider

[1] P 195, FERC Order No. 901; https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false; October 17, 2023

tolerances for frequency and voltage excursions. This is the reason for the differences in the frequency and voltage tables and graphs between the two standards.

The proposed PRC-029 must be understood as an event-based standard. Compliance with PRC-029 is determined from IBR ride-through performance during transmission system events in the field and not from interconnection studies, transmission planning studies, operational planning studies, or from IBR models. An IBR becomes noncompliant with PRC-029 only when an event in the field occurs that shows that one or more requirements were not satisfied. This intent is clarified by *Operations Assessment* as the Time Horizon designation of requirements R1-R5.

FERC Order No. 901 Directives

PRC-029-1 is proposed in consideration of directives from FERC Order No. 901 that were assigned to the Project 2020-02 drafting team. The following directives were assigned to this drafting team for inclusion in this Standards Project (paragraph numbers of the FERC Order are included for reference):

- Paragraph 190: “Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults.”
- Paragraph 190: “The new or modified Reliability Standards must require registered IBRs to continue to inject current and perform frequency support during a Bulk-Power System disturbance.”
- Paragraph 190: “Any new or modified Reliability Standard must also require registered IBR generator owners and operators to prohibit momentary cessation in the no-trip zone during disturbances.”
- Paragraph 190: “NERC must submit new or modified Reliability Standards that establish IBR performance requirements, including requirements addressing frequency and voltage ride through, post-disturbance ramp rates, phase lock loop synchronization, and other known causes of IBR tripping or momentary cessation.”
- Paragraph 193: “Therefore, we direct NERC through its standard development process to determine whether the new or modified Reliability Standards should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements.”
- Paragraph 193: “Further, we direct NERC to ensure that any such exemption would be applicable for only existing equipment that is unable to meet voltage ride-through performance. When such existing equipment is replaced, the exemption would no longer apply, and the new equipment must comply with the appropriate IBR performance requirements specified in the Reliability Standards (e.g., voltage and frequency ride through, phase lock loop, ramp rates, etc.).”

- Paragraph 193: "Finally, we direct NERC, through its standard development process, to require the limited and documented exemption list (i.e., IBR generator owner and operator exemptions) to be communicated with their respective Bulk-Power System planners and operators (e.g., the IBR generator owner's or operator's planning coordinator, transmission planner, reliability coordinator, transmission operator, and balancing authority)."
- Paragraph 199: "Pursuant to section 215(d)(5) of the FPA, we modify the NOPR proposal. To the extent NERC determines that a limited and documented exemption for those registered IBRs currently in operation and unable to meet voltage ride-through requirements is appropriate due to their inability to modify their coordinated protection and control settings, we direct NERC to develop new or modified Reliability Standards to mitigate the reliability impacts to the Bulk-Power System of such an exemption."
- Paragraph 208: "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop and submit to the Commission for approval new or modified Reliability Standards that require post-disturbance ramp rates for registered IBRs to be unrestricted and not programmed to artificially interfere with the resource returning to a pre-disturbance output level in a quick and stable manner after a Bulk-Power System."
- Paragraph 209: "The proposed new or modified Reliability Standards must require registered IBRs to ride through momentary loss of synchronism during Bulk-Power System disturbances and require registered IBRs to continue to inject current into the Bulk-Power System at pre-disturbance levels during a disturbance, consistent with the IBR Interconnection Requirements Guideline and Canyon 2 Fire Event Report recommendations."
- Paragraph 209: "Related to ACP/SEIA's comment recommending to revise the directive to require generators to maintain synchronism where possible and continue to inject current to support system stability, we direct NERC, through its standard development process, to consider whether there are conditions that may limit generators to maintain synchronism."
- Paragraph 226: "Further, we believe that there is a need to have all of the directed Reliability Standards effective and enforceable well in advance of 2030 and direct NERC to ensure that the associated implementation plans sequentially stagger the effective and enforceable dates to ensure an orderly industry transition for complying with the IBR directives in this final rule prior to that date." (*pertains multiple projects*)

Rationale for Applicability Section (4.0)

Functional Entities (4.1)

The functional entity responsible for assuring acceptable ride-through performance of IBR is the Generator Owner (GO) and Transmission Owner (TO).

Facilities (4.2)

Applicability Facilities includes only those IBR that also meet NERC registration criteria. Language used within PRC-029-1 applicability only refers to IBR as a whole plant/facility. Consistent with FERC Order No. 901, IBR performance is based on the overall IBR plant and disturbance monitoring equipment requirements established under the proposed PRC-028-1. Requirements within PRC-029-1 do not apply to individual inverter units or measurements taken at individual inverter unit terminals.

Rationale for Requirement R1

The objective of Requirement R1 is to ensure an applicable IBR will ride-through a grid voltage disturbance consistent with the no-trip zone and Operation Regions specified in **Attachment 1**. IBR must be able to demonstrate performance that they remain electrically connected, i.e., shall not trip, and continue to exchange current, i.e., shall not enter momentary cessation.

The drafting team determined that the definition of “no-trip zones” and “Operation Regions” should be consistent with those terms as used within IEEE 2800-2022. Additionally, the team determined the voltage thresholds of each Operation Region are based on measurements taken on the high-side of the main power transformer in PRC-029-1.

Exceptions to **Attachment 1** performance criteria are allowable when 1) an IBR needs to trip to clear a fault within its zone of protection, and 2) a documented equipment limitation prevents an IBR from riding through the disturbance in accordance with Requirement R6.

Rationale for Requirement R2

In addition to having minimum voltage ride-through capability specified in Requirement R1, an applicable IBR is also required to adhere to certain voltage ride-through performance criteria during a system disturbance. Acceptable performance criteria is dependent on the Operation Region that an IBR is presently in, or it’s change from one Operation Region to another Operation Region. Requirement R2 includes specific performance criteria and is needed to assure consistent IBR performance during each Operation Region in **Attachment 1**.

Rationale for Requirement R2.1

This subpart of Requirement 2 ensures, when the voltage at the high-side of the main power transformer (MPT) recovers to the Continuous Operation Region from either the Mandatory Operation Region or the Permissive Operation Region, an IBR is expected to deliver the pre-disturbance level of active power or available active power, whichever is less. This requires an IBR to exit the “High Voltage Ride Through (HVRT)” or “Low Voltage Ridge Through (LVRT)” modes properly such that it does not cause reduction in the active power when the system already recovers the voltage within the Continuous Operation Region.

When the voltage at the high-side of the MPT is greater than 0.9 per-unit and less than 0.95 per-unit, IBRs are expected to exit the LVRT mode and come back to “normal operating mode”. If an IBR has a default total current limit of 1.0 per-unit, the apparent power production of an IBR will be limited to be below 1.0 per-unit (e.g., the per-unit value of IBR terminal voltage). In such case, IBR needs to configure a preference setting, either to maintain pre-disturbance active power or maximize the reactive power in order to further help with voltage recovery, according to requirements specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Rationale for Requirement R2.2

This subpart of Requirement 2 ensures when the voltage at the high-side of the MPT is within the Mandatory Operation Region, IBRs are expected to enter the HVRT and LVRT mode such that it will inject or absorb reactive current proportional to the level of terminal voltage deviations it measures. IBR shall follow Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specified certain magnitude of reactive power response to voltage changes, if available.

By default, reactive current prioritization shall be configured unless Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires active power priority.

Rationale for Requirement R2.3

This subpart of Requirement 2 ensures when a fault is cleared on the transmission system, the voltage regulators of connected IBRs must adjust the reactive current injection to restore the transmission system voltage to the pre-disturbance voltage as defined by the automatic voltage regulator (AVR) setpoint. The drafting team acknowledges that tuning of the AVR requires a balance between multiple competing physical factors, e.g., rise time, overshoot, and transient stability. However, it is anticipated that IBR controls will be tuned to allow for a stable post-disturbance voltage recovery without causing excessive overshoot or undershoot of the setpoint. When such overshoots do occur, they must not exceed the magnitude and duration of the applicable table given in **Attachment 1**. Furthermore, this standard anticipates that control system tuning to prevent such over/under voltages will focus on the speed at which the controller responds to setpoint changes rather than on the magnitude of the reactive current response. For example, reductions in k-factor to prevent over/under voltages should only be considered as a last resort.

Rationale for Requirement R2.4

This subpart of Requirement 2 ensures that IBR returns to effective pre-disturbance operation unless otherwise specified or needed by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Rationale for Requirement R2.5

This subpart of Requirement 2 ensures that voltage protection settings of IBR are based on maximum equipment capabilities rather than settings based directly on, or just outside, of the no-trip zone.

Rationale for Requirement R3

The objective of Requirement R3 is to provide transient overvoltage ride-through for IBR during the non-fault switching event. Voltage transients are commonly occurring on the BPS due to switching actions, fault clearing, lightning, etc. IBR shall ride-through the transient overvoltage condition specified in **Attachment 2** during the non-fault switching events in the transmission systems. During this transient overvoltage event, IBRs should continue to inject current, but it does not have to respond to transient overvoltage, i.e., enter reactive priority mode and/or change magnitude of current output.

If necessary, IBRs may operate in current blocking mode, when instantaneous voltage exceeds 1.2 p.u., to help ensure stable response that does not lead to tripping and to eliminate the IBR as a possible cause for the overvoltage. If IBRs operate in the current blocking mode, it shall restart current exchange in less than or equal to five cycles following instantaneous voltage falling below, and remaining below, 1.2 p.u. This is different than momentary cessation, which involves a resource returning over a longer time frame with a specified delay and ramp rate.

The drafting team notes that IBR should not be set to trip on an instantaneous, unfiltered voltage measurements, except due to known equipment limitations.

Rationale for Requirement R4

The objective of Requirement R4 is to ensure that IBR remains electrically connected and exchanging current during a frequency excursion event.

Grid frequency reflects the balance of system generation and load. A system event that causes a generation/load imbalance will cause system frequency to deviate from nominal. The system may experience an over-frequency event (in the case of more generation than load) or an under-frequency event (in the case of less generation than load). Inertia resists the deviation from nominal frequency, giving the operators additional time to rebalance generation and load. System inertia depends on the amount of rotating mass connected to the system (such as the synchronous generators or motors). The larger the system inertia, the slower the system frequency will deviate from the nominal value and the lower the grid Rate Of Change Of Frequency (ROCOF), giving more time to try to rebalance generation and load. Also, higher system inertia may minimize the risk of Cascading generation loss caused by the operation of generator frequency protection.

A reduction in system inertia is an inevitable consequence of a power system transiting toward more IBR and less synchronous generators. As discussed in the previous paragraph, less system inertia means the frequency will deviate from the nominal value more quickly during a generation/load imbalance event and will expose the system to a higher ROCOF. A wider frequency ride-through capability for IBR may be required to avoid the risk of widespread tripping. To reduce the risk of widespread IBR tripping during frequency disturbances, and more generally to ensure the reliability of future grids with high IBR penetration, the drafting team proposes a 6-second frequency ride-through capability requirement for frequencies in the ranges of 61.8Hz to 64Hz or 57.0Hz to 56.0Hz range. The proposed 6-second time frame of the frequency ride-through capability requirement is beyond the IEEE 2800 standard frequency ride-through requirement and beyond frequency ride-through requirements for synchronous machines under proposed PRC-024-4.

IBR lacks the inertia and short circuit contributions of synchronous machines. To compensate for the lack of inertia and short circuit contributions, they should have wider tolerances for frequency and voltage excursions to meet the future power system with a higher percentage of IBR. Synchronous resources are more sensitive to frequency deviations than IBR resources. All IBR resources (except for type 3 wind turbines) interface to the grid through fast switching of power electronics devices. These power electronic devices are much less sensitive to the transmission system frequency excursion than non-hydraulic turbine synchronous resources (steam turbines and combustion turbines). In the case of the non-hydraulic turbine synchronous resources, the turbine is usually considered to be more restrictive than the generator in limiting IBR frequency ride-through because of possible mechanical resonances in the many stages of turbine blades. Off-nominal frequencies may bring blade vibrational frequencies closer to a mechanical resonate frequency and cause damage due to the vibration stresses. However, inverter-interfaced-IBR does not share this vibrational failure mode. Therefore, IBR should be capable of riding through the increased proposed 6-second frequency ride-through requirement without risk of equipment damage or need for frequency protection to operate.

Requirement R4 does not prescribe specific frequency protection settings for IBR equipment. IBR frequency protection settings should only be set to protect the IBR from damage caused by operation at off-nominal frequency. An IBR owner must ensure that the IBR frequency protection does not prevent an IBR from meeting the R4 ride-through requirement.

This standard requires that IBR remains electrically connected and continues to exchange current during a frequency excursion event in which the frequency remains within the no-trip zone\ according to **Attachment 3** and the absolute ROCOF magnitude is less than or equal to 5 Hz/second. Some IBR controllers and their ability to remain electrically connected and continue to exchange current to the grid are sensitive to ROCOF during a frequency excursion event. If needed to maintain the stability of the IBR or prevent equipment damage, the R4 requirement allows the IBR to trip for an absolute ROCOF exceeding 5Hz/sec within the no-trip zone as shown in **Attachment 3**. Failure to ride-through due to ROCOF exceeding 5Hz/sec shall only be allowed during a generator/load imbalance event that causes the frequency to deviate from nominal.

The ROCOF protection should not operate at the onset of a fault, during a fault, or at fault clearance, i.e., it should be disabled for faults. The IBR shall ride-through any system disturbance while the voltage at the high side of the main power transformer remains within the no-trip zones as specified in **Attachment 1**. Furthermore, to reduce the risk of IBR tripping on ROCOF protection, ROCOF shall be calculated as the average rate of change for multiple calculated system frequencies for some time greater than or equal to 0.1 seconds.

Rationale for Requirement R5

The objective of Requirement R5 is to ensure IBR remains electrically connected and exchanging current during instantaneous positive sequence voltage phase angle changes initiated by certain non-fault switching events.

Unlike synchronous generators, for which the synchronization mechanism to the grid is naturally preserved by the inertia, the grid following voltage source inverters (VSI) used for the majority of existing IBR facilities are equipped with the Phase-lock-loop (PLL) device for synchronization purposes. A typical synchronous reference frame PLL schematic is given in Fig. 1, where the three-phase voltages in the abc reference frame (v_a, v_b, and v_c) are transformed to the dq frame (v_d’ and v_q’) by the Park’s transformation and the phase angle θ is controlled by a feedback loop that regulates the q component to zero.

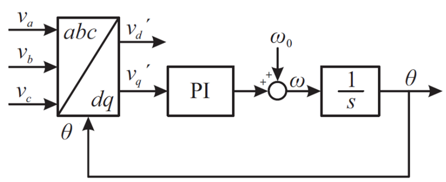

Figure 1: Schematic Diagram of a Synchronous Reference Frame PLL

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When the inverter operates in the steady state, it is locked to the grid voltage via the PLL, assuming the PI controller is well tuned. In this case the phase displacement between the grid voltage and that measured by the PLL, Δθ is zero, as shown in Fig. 2.

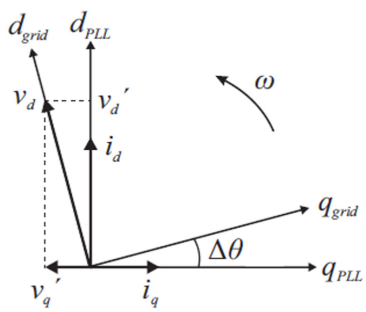

Figure 2: Phasor Diagram of Grid Voltage and Current

When a grid disturbance occurs, such as a close-in fault or a relatively large switching event, the grid voltage may experience a rapid phase angle shift. In such cases, the phase displacement Δθ can be large enough to pose challenges for the PLL to track the terminal voltage, cause control instability within the inverter, such as the inner current control loop or the DC link control loop, and even lead to tripping of the inverter due to the malfunction of the controls.

Since phase angle jumps are common occurrences on the BPS, this standard requires the IBR to be designed and operated to ride-through a minimum phase angle jump of 25 electrical degrees. This is a typical value and aligns with the requirement in IEEE 2800 2022. Furthermore, for a phase angle jump of 25 degrees or more, the IBR shall only trip to prevent equipment damage.

Some IBR equipment has PLL loss of synchronism protection, referring to a protective function that operates when the angle displacement Δθ exceeds a threshold for a predetermined period of time (on the order of a couple of milliseconds). Historically, this protection has been used by some inverter manufacturers, especially for inverters in distribution systems. For the IBR connected to the BPS, this protection function should be disabled. If it is enabled, the phase angle jump protection setting shall be configured such that the IBR shall only trip to prevent equipment damage.

Rationale for Requirement R6

The objective of Requirement R5 is to ensure legacy IBR may need to obtain an exemption to the voltage ride-through requirements if hardware replacements or other costly upgrades would be necessary to comply with Requirements R1 or Requirement R2. This provision allows such exemptions as long as such limitations are documented and communicated to the Planning Coordinator, and Reliability Coordinator of the respective footprints in which the IBR project is located. The Planning Coordinator, and Reliability Coordinator will then need to take the voltage ride-through limitations into account in planning and operations.

Limitations must not be construed as complete exemptions from the applicable **Attachment 1** table but must be specific as to which voltage band(s) and associated duration(s) cannot be satisfied or specific as to the number of cumulative voltage deviations within a ten-second time period that the equipment can ride-through if less than four. Limitation descriptions should identify the specific equipment and explain the characteristic(s) of that equipment that prevent ride-through. If any equipment limitation is removed or otherwise corrected, it is likewise necessary to communicate to the Planning Coordinator, and Reliability Coordinator of this.

FERC Order No. 901 states that this provision would be limited to exempting “certain registered IBRs from voltage ride-through performance requirements.” This is the reason that no similar provisions are included for exemptions for frequency, rate-of-change-of-frequency (ROCOF) ,phase angle change ride-through requirements.

Violation Risk Factor and Violation Severity Level Justifications

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
PRC-024-4

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-024-4. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to BulkPower System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to BulkPower System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System. However, violation of a medium risk requirement is unlikely to lead to Bulk- Power System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BulkPower System, or the ability to effectively monitor, control, or restore the BulkPower System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

The VRF did not change from the previously FERC approved PRC-024-3 Reliability Standard.

VSLs for PRC-024-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to set its applicable frequency protection so that it does not trip according to Requirement R1.

VSL Justifications for PRC-024-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement adds a functional entity. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-024-4, Requirement R1	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

The VRF did not change from the previously FERC approved PRC-024-3 Reliability Standard.

VSLs for PRC-024-4, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
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 according to Requirement R2.

VSL Justifications for PRC-024-4, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement adds a functional entity. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-024-4, Requirement R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

The VRF did not change from the previously FERC approved PRC-024-3 Reliability Standard.

VSLs for PRC-024-4, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner or Transmission 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 or Transmission 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 or Transmission 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 or Transmission 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 or Transmission Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.

VSL Justifications for PRC-024-4, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement adds a functional entity. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for PRC-024-4, Requirement R3	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

The VRF did not change from the previously FERC approved PRC-024-3 Reliability Standard.

VSLs for PRC-024-4, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner or Transmission Owner provided its protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner or provided protection settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner or Transmission Owner failed to provide its protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner failed to provide protection settings within 150 calendar days of a written request.

VSL Justifications for PRC-024-4, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement adds a functional entity. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-024-4, Requirement R4	
Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

Violation Risk Factor and Violation Severity Level Justifications

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
PRC-029-1

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-029-1. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to BulkPower System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to BulkPower System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System. However, violation of a medium risk requirement is unlikely to lead to Bulk- Power System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BulkPower System, or the ability to effectively monitor, control, or restore the BulkPower System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC’s overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.
Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justifications for PRC-029-1, Requirement R1	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate as applicable generating resources must be able to ride-through system disturbances. Failure to ride-through has been documented in multiple NERC reports leading to exacerbated system conditions, resulting in the electrical disconnecting of additional generation and widespread outages.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Similar requirements in PRC-024-3 are identified as Medium but are based on equipment protection setting documentation rather than actual, recorded performance during a grid disturbance. Therefore, this VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable IBR remains electrically connected and continued to exchange current in accordance with Attachment 1, unless needed to clear a fault, in accordance with Requirement R1.

VSL Justifications for PRC-029-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R1	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R2	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate as applicable generating resources must be able to ride-through system disturbances. Failure to ride-through has been documented in multiple NERC reports leading to exacerbated system conditions, resulting in the electrical disconnecting of additional generation and widespread outages.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Similar requirements in PRC-024-3 are identified as Medium but are based on equipment protection setting documentation rather than actual, recorded performance during a grid disturbance. Therefore, this VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable IBR adhered to performance requirements during each System disturbance, as specified in Requirement R2.

VSL Justifications for PRC-029-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R3	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate that if violated, it would not be expected to adversely affect the electrical state or capability of the Bulk-Power System.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of Lower VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a Lower VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable IBR adhered to performance requirements during each transient overvoltage period as specified in Requirement R3.

VSL Justifications for PRC-029-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R3	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R4	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate that if violated, it would not be expected to adversely affect the electrical state or capability of the Bulk-Power System.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of Lower VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a Lower VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable IBR adhered to performance requirements during each frequency excursion event, as specified in Requirement R4.

VSL Justifications for PRC-029-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R4	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R5	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate that if violated, it would not be expected to adversely affect the electrical state or capability of the Bulk-Power System.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of Lower VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a Lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable IBR adhered to performance requirements during each instantaneous positive sequence voltage phase angle change of less than 25 electrical degrees, as specified in Requirement R5.

VSL Justifications for PRC-029-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R5	
Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R6	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate that if violated, it would not be expected to adversely affect the electrical state or capability of the Bulk-Power System.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of Lower VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a Lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator, Transmission Planner, and Reliability Coordinator more than 30 calendar days but less than or equal to 60 calendar days after the change to the equipment.	The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator, Transmission Planner, and Reliability Coordinator more than 60 calendar days but less than or equal to 90 calendar days after the change to the equipment.	The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator, Transmission Planner, and Reliability Coordinator more than 90 calendar days but less than or equal to 120 calendar days after the change to the equipment.	The Generator Owner or Transmission Owner failed to document evidence of equipment limitations consistent with Requirement R6 and prior to the effective date of PRC 029 1 Requirement R6. OR The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator, Transmission Planner, and Reliability Coordinator more than 120 calendar days after the change to the equipment.

VSL Justifications for PRC-029-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for PRC-029-1, Requirement R6	
Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2020-02 Modifications to PRC-024 (Generator Ride-through) | PRC-024-4 and PRC-029-1

Formal Comment Period Open through April 22, 2024
Ballot Pools Forming through April 5, 2024

Now Available

A 25-day formal comment period for **Project 2020-02 Modifications to PRC-024 (Generator Ride-through)**, is open through **8 p.m. Eastern, Monday, April 22, 2024**.

The Standards Committee approved waivers to the Standard Processes Manual at their December 2023 meeting. These waivers were sought by NERC Standards staff for reduced formal comment and ballot periods. This will assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 901. *FERC Order 901 was issued under* Docket No. RM22-12-000 *on October 19, 2023.*

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Friday, April 5, 2024.** Registered Ballot Body members can join the ballot pools here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*

- *Please be mindful of ballot and comment period closing dates. We ask to* ***allow at least 48 hours*** *for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts* ***prior to the last day*** *of a comment/ballot period.*

Next Steps

Initial ballots for the standards and implementation plan, as well as non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **April 12 - 22, 2024**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Manager of Standards Development, Jamie Calderon (via email) or at 404-960-0568 Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2020-02 Modifications to PRC-024 (Generator Ride-through) observer list” in the Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2020-02 Modifications to PRC-024 (Generator Ride-through) | Draft 1
Comment Period Start Date:	3/27/2024
Comment Period End Date:	4/22/2024
Associated Ballots:	2020-02 Modifications to PRC-024 (Generator Ride-through) Implementation Plan IN 1 OT 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-024-4 | Non-binding Poll IN 1 NB 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-024-4 IN 1 ST 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-029-1 | Non-binding Poll IN 1 NB 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-029-1 IN 1 ST

There were 79 sets of responses, including comments from approximately 180 different people from approximately 111 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the need for creating a new Standard (PRC-029-1) to address gaps the Inverter-Based Resource Performance Subcommittee (IRPSC) identified within the PRC-024-3 Project 2020-02 SAR and to address the expectations of FERC Order No. 901?

2. Do you agree that the language within PRC-029-1 requirements R1, R2, and R6 regarding IBR plant-level performance during grid voltage disturbances is clear?

3. Do you agree with the drafting team's proposals for including IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in PRC-029-1 Requirements R3, R4, and R5?

4. Provide any additional comments for the Drafting Team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
Santee Cooper	Carey Salisbury	1,3,5,6		Santee Cooper	Lachelle Brooks	Santee Cooper	1,3,5,6	SERC
					Paul Camilletti	Santee Cooper	1,3,5,6	SERC
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
Southern Company - Southern Company Services, Inc.	Colby Galloway	1,3,5,6	MRO,RF,SERC,Texas RE,WECC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC

					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
California ISO	Darcy O'Connell	2	WECC	ISO/RTO Council (IRC) Standards Review Committee	Ali Miremadi	California ISO	2	WECC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Helen Lainis	Independent Electricity System Operator	2	NPCC
					Elizabeth Davis	PJM Interconnection	2	RF
					Charles Yeung	Southwest Power Pool, Inc.	2	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
Austin Energy	Imane Mrini	6		Austin Energy	Imane Mrini	Austin Energy	6	Texas RE
					Michael Dillard	Austin Energy	5	Texas RE
					Lovita Griffin	Austin Energy	3	Texas RE
					Tony Hua	Austin Energy	4	Texas RE
					Thomas Standifur	Austin Energy	1	Texas RE
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC

					John Nierenberg	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	SERC
					Sara Orr	Golden Spread Electric Cooperative, Inc.	5	Texas RE
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF

					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Micah Runner	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC

David Burke	Orange and Rockland	3	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
David Kwan	Ontario Power Generation	4	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
Sean Cavote	PSEG	4	NPCC
Jason Chandler	Con Edison	5	NPCC
Tracy MacNicoll	Utility Services	5	NPCC
Shivaz Chopra	New York Power Authority	6	NPCC
Vijay Puran	New York State Department of Public Service	6	NPCC
David Kiguel	Independent	7	NPCC
Joel Charlebois	AESI	7	NPCC
Joshua London	Eversource Energy	1	NPCC
Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
Chantal Mazza	Hydro Quebec	1,2	NPCC

					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Chantal Mazza	Hydro Quebec	1,2	NPCC
					Nicolas Turcotte	Hydro-Quebec (HQ)	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Joel Charlebois	AESI	7	NPCC
Elevate Energy Consulting	Ryan Quint	NA - Not Applicable	NA - Not Applicable	Elevate Energy Consulting	Ryan Quint	Elevate Energy Consulting		NA - Not Applicable
					N/A	N/A		NA - Not Applicable
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Stephen Whaite	Stephen Whaite		RF	ReliabilityFirst Ballot Body Member and Proxies	Lindsey Mannion	ReliabilityFirst	10	RF
					Stephen Whaite	ReliabilityFirst	10	RF
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC

					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Gary Dollins	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Olivia Olson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	SERC
					Heath Henry	NW Electric Power	3	SERC

							Cooperative, Inc.		
						Tony Gott	KAMO Electric Cooperative	3	SERC
						Micah Breedlove	KAMO Electric Cooperative	1	SERC
						Brett Douglas	Northeast Missouri Electric Power Cooperative	1	SERC
						Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
						Mark Riley	Associated Electric Cooperative, Inc.	1	SERC
						Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
						Chuck Booth	Associated Electric Cooperative, Inc.	5	SERC
						Jarrod Murdaugh	Sho-Me Power Electric Cooperative	3	SERC

1. Do you agree with the need for creating a new Standard (PRC-029-1) to address gaps the Inverter-Based Resource Performance Subcommittee (IRPSC) identified within the PRC-024-3 Project 2020-02 SAR and to address the expectations of FERC Order No. 901?

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
We recommend adding these IBR related requirements to PRC-024, rather than creating a new Standard.	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation does not agree with creating a new IBR specific standard (PRC-29) to address the gaps in the Inverter-Based Resource. While Constellation recognizes that there has been some grid disturbance in the Odessa/California/Utah regions in the past couple years as a result of some IBRs not performing as intended, the creation of a new standard is a quick reaction without ensuring existing equipment's are capable to fully comply. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE supports creating a new standard to address Inverter-Based Resources (IBR) gaps identified. Texas RE is concerned, however, with the structure of the standard as it is presently proposed.

As currently drafted, the proposed PRC-029-1 would wholly eliminate existing frequency and voltage protection setting verification requirements for IBR resources. Texas RE submits that this is contrary to FERC's intent in directing NERC to develop a comprehensive ride-through standard for IBR resources. FERC Order No. 901 explicitly directs NERC to draft a standard "that require[s] IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system excursions and that permit IBR tripping only to protect IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults." (Order No, 901, paragraph 190). FERC's intent behind the order was to expand the scope of applicable devices beyond protection system equipment subject to the current PRC-024 requirements to embrace a range of devices that can trip an IBR facility (inverters, plant controller, etc.). The ultimate goal is to better ensure that IBRs provide reliable performance during voltage and frequency excursions.

Texas RE submits, however, that FERC did not intent to exclude IBR entities from the existing verification processes or significant limit the ability of the ERO to review protection system settings prior to an actual disturbance event. In its order, FERC specifically referenced the 2021 Odessa Disturbance Report jointly prepared by NERC and Texas RE staff ("2021 Odessa Disturbance Report"). The 2021 Odessa Disturbance Report in turn called for the development of a ride-through standard to replace PRC-024-3 because "the events analyzed by NERC regarding fault-induced reductions in solar PV output and wind output have identified issues with controls and protections unrelated to voltage and frequency." (2021 Odessa Report, at 29). While calling for a more comprehensive standard, however, the report simultaneously identified pervasive issues with protection system settings within the scope of the current PRC-024 standards. The report noted: "Numerous plant owner/operators have stated that they do not have sufficient technical staff on hand to interpret the results and will simply install what the consultant recommends. This is leading to poorly coordinated protection systems within the facility, causing unreliable performance from BPS-connected solar PV facilities in multiple interconnections." (2021 Odessa Report, at 17 (emphasis added)). In short, while acknowledging that the current PRC-024 standard is overly narrow, FERC and the various reports FERC references make clear that protection system verification failures remain an important contributing factor in the numerous disturbance events involving IBRs over the past few years.

As proposed, PRC-029-1 would result in a reliability gap by requiring that protection system settings no longer require verification. The Standard Drafting Team (SDT) explains in the draft PRC-029-1 Technical Rationale that "[a]n IBR becomes noncompliant with PRC-029 only when an event in the field occurs that shows that one or more requirements were not satisfied." Under the SDT's proposed approach, therefore, the existing PRC-024 protection system setting verification requirements would be eliminated and the sole mechanism to verify performance would be an IBR's failure to perform during a disturbance event. Texas RE posits that this approach is inconsistent with the intent of FERC's order to expand the applicable devices and settings that an IBR-entity must ensure are properly set to avoid unnecessary tripping during events. It is also inconsistent with findings that entities continue to experience issues properly setting (and verifying) existing protection systems within the scope of the current PRC-024 requirements.

Rather than pursue this approach, Texas RE suggests that the SDT consider retaining the existing protection system verification requirements as a foundational step, but augment those requirements with a general performance standard. Moreover, while Texas RE does not believe the SDT needs or should develop a comprehensive and prescriptive list of devices that must be appropriate set and coordinated to ensure IBR performance, the SDT should consider which measures and evidence would be appropriate for the GO and TO to demonstrate that its settings meet the various no-trip zone parameters described in Attachment 1. This should include sufficient evidence to show that protection system settings are properly set to not trip within appropriate no trip zones, as well as that other settings for inverters, plant controllers, and other devices are properly coordinated. Such clarity will ensure that at least minimum performance can be audited and verified prior to a disturbance event – the goal of the standards process.

Additionally, Texas RE noticed during the webinar, SDT stated that the requirements do not apply to individual IBR units. Requirement R1 seems to indicate that each IBR unit needs to remain electrically connected and continue to exchange current in accordance with the no-trip zones and operation regions.

Lastly, Texas RE recommends the SDT consider changing 'each IBR' to 'each IBR Facility' for all the Requirements.

Likes 0	
Dislikes 0	

Response

Joy Brake - Nova Scotia Power Inc. - NA - Not Applicable - NPCC

Answer	No
Document Name	

Comment

A performance standard should be based on function not technology type which is always changing. An IBR generation facility should meet the same performance threshold as traditional generation, with additional support devices as necessary incorporated into the facility design to meet the same level of performance as a traditional unit.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

PRC-024-3 has not been in effect long enough to be deemed inadequate to address "gaps" and issues described in IBR disturbance reports. It became effective on 10/1/2022, which was long after major disturbances occurred, and as written, covers major causes of IBR disturbances such as voltage, frequency, and momentary cessation. Most importantly, the Standard clearly stated applicability to individual IBR units and it clearly stated no-trip zones. The Standard could have been modified to include and cover other recommendations from the disturbance report such as PLL protection and ramp rate mis-coordination.

Likes 0	

Dislikes 0	

Response

Alison MacKellar - Constellation - 5	
Answer	No
Document Name	

Comment

Constellation does not agree with creating a new IBR specific standard (PRC-29) to address the gaps in the Inverter-Based Resource. While Constellation recognizes that there has been some grid disturbance in the Odessa/California/Utah regions in the past couple years as a result of some IBRs not performing as intended, the creation of a new standard is a quick reaction without ensuring existing equipment's are capable to fully comply.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Michael Goggin - Grid Strategies LLC - 5	
Answer	No
Document Name	

Comment

A major concern with the separate Standards, as drafted, is that ride through performance is not required for synchronous generators under PRC-024-4, but it is for IBRs under PRC-029. PRC-02-4 simply requires protective relays to be set so they do not trip the generator within specified bounds, but it allows a resource to trip offline for other reasons. PRC-024-4 also allows a plant to trip if protection systems trip auxiliary plant equipment, per section 4.2.3. In contrast, PRC-029 requires IBRs to remain electrically connected and to continue to exchange current within the specified voltage and frequency bounds. Said another way, an IBR and a synchronous resource could both trip during the same disturbance, and the IBR would be in violation of PRC-029 but the synchronous generator would not be in violation of PRC-024-4, as long as the synchronous generator did not trip due to the settings of its protection system.

To ensure grid reliability and resilience, all resources including IBRs and synchronous resources should ride through grid disturbances. The failure of synchronous generators to ride through grid disturbances threatens grid reliability as much or more than the failure of IBRs, as synchronous resources are often producing at a higher level of output, are more typically relied on as capacity resources, and often take longer to come back online and ramp up to full output if they trip due to a disturbance.

FERC Order 901 directed NERC to treat IBR resources similarly to how NERC Standards treat synchronous generators, writing that the IBR Standard should “permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults."{C}[1] Allowing synchronous generators to trip but requiring IBRs to ride through the same or similar disturbance could be challenged at FERC as undue discrimination.

Not requiring ride-through performance from synchronous generators is also at odds with the intent for this project that NERC stated in its February 2023 comments on the FERC proposed rulemaking that led to Order 901: "A comprehensive, performance-based ride-through standard is needed to assure future grid reliability. To that end, NERC re-scoped an existing project, Project 2020-02 Modifications to PRC-024 (Generator Ride-through), to revise or replace current Reliability Standard PRC-024- 3 with a standard that will require ride-through performance from all generating resources."[2] FERC's Order 901 also noted NERC's statement that this project would require ride-through performance from all generating resources,[3] so a failure to require ride-through performance from synchronous generators may be contrary to both NERC and FERC's intent.

The drafting team should make PRC-024-4 a ride-through performance requirement like PRC-029, or alternatively create a single standard that applies to both types of resources (with any necessary clarifications or minor differences in requirements to reflect the differences in IBR and synchronous generator technologies).

{C}[1]{C} Order 901, https://www.ferc.gov/media/e-1-rm22-12-000, at paragraph 190

{C}[2]{C}https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Comments_IBR%20Standards%20NOPR.pdf, at 21-22

{C}[3]{C} Order 901, https://www.ferc.gov/media/e-1-rm22-12-000, at paragraph 185

Likes 0	
Dislikes 0	

Response

Carey Salisbury - Santee Cooper - 1,3,5,6, Group Name Santee Cooper

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

David Campbell - David Campbell On Behalf of: Natalie Johnson, Enel Green Power, 5; - David Campbell

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
While AEP agrees with creating PRC-029-1 to address the identified gaps, AEP recommends the SDTs for PRC-028, PRC-029 and PRC-030 review each proposed standard obligations to ensure there is a consistent, integrated plan across these projects and standards to achieve the goal of correcting the past performance of Invertor-Based Resources and IBR units. Having a coherent strategy document that explains how these three standards complement each other (and not be duplicative) would be beneficial.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Synchronous generation and Inverter-based resources should have separate standards due to their unique differences. Presently, behavior of Synchronous generation during disturbances and faults is very well understood compared to IBR technology.	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	IESO Comments for PRC-024 PRC-029 Draft 1.docx
Comment	

Complete set of comments for all Qs attached in file: IESO Comments for PRC-024 and PRC-029 Draft 1	
Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
Yes, we need a separate a standard. The technologies are different enough that a separate standard will reduce confusion.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
AECI supports comments provided by the NAGF	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy supports the need for the new standard (PRC-029-1).	

In addition, FE supports EEI's comments which state:

EEI agrees with most of the proposed language in Requirements R1, R2 and R6; however, the phrase "of an applicable IBR" should be removed. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant.

Additionally, Requirement R2, subpart 2.5 could be understood to mean that IBRs whenever the voltage at the high-side of the main power transformer is within the no-trip zone, as specified in Attachment 1, must not trip even if it might lead to equipment damage. We offer the following proposed edits in boldface to Requirement R2, subpart 2.5 to clarify the requirement. NERC Reliability Standards should never mandate that equipment run to failure.

2.5 **Each IBR shall only trip to prevent equipment damage, W**hen**ever** the voltage at the high-side of the main power transformer is within **of** the no-trip zone, as specified in Attachment 1, **each IBR shall continue to operate except when the continued operation of the IBR would lead to equipment damage**.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	Yes
Document Name	

Comment

Black Hills Corporation agrees that there is a gap in PRC-024-3 regarding performance of inverter-based resources (IBR). However, more consideration should be given to creating "protection-based" Standards for IBR, whether as an update to existing Standard PRC-024-3 or new Standard PRC-029-1 rather than the "event-based" approach currently being taken in PRC-029-1.

Likes 0	
Dislikes 0	

Response

Stefanie Burke - Portland General Electric Co. - 6

Answer	Yes
Document Name	

Comment

PGE requests that the Standard Drafting Team (SDT) add clarity regarding Attachment A: Voltage Boundary Clarifications, Section: Evaluating Protection Settings, a. The most probable real and reactive loading conditions for the unit under study.

Loading conditions vary depending on the type of unit, location, time of year, etc. How should an entity assess “most probable” loading conditions? Are entities being required to account for the worst case scenarios providing the greatest voltage change(s), not just a probable condition that may represent little to no significant voltage difference?

PGE also notes that the Table References and Figure References are not aligned

Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	

Yes, the technological differences warrant separate standards for IBRs and synchronous generation.

Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	

Ameren agrees with EEI's comments.

Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	

Yes, the technological differences warrant separate standards for IBRs and synchronous generation.

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	Yes
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	Yes
Document Name	

Comment

Duke Energy recommends the implementation of EEI comments.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

EEI supports the development of a new Reliability Standard to address gaps in Inverter-Based Resource Performance and while the SAR does not include any language that specifically addresses FERC Order No. 901, EEI has no concerns with the SDT adjusting PRC-029 in line with the directives contained in this Order.

Likes 0	
Dislikes 0	

Response

Imane Mrini - Austin Energy - 6, Group Name Austin Energy

Answer	Yes
Document Name	

Comment

AE supports comments provided by Texas RE and the NAGF

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Maozhong Gong - GE - GE Wind - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

But we have additional comments.

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	Yes
Document Name	

Comment

SRP believes that there is a huge lack of oversight in regard to inverter-based resources. Regulation on IBR controls is somewhat late but we are glad is happening.

Likes 0	
Dislikes 0	

Response

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers

Answer	Yes
Document Name	

Comment

Vistra agrees with AEP.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	Yes
Document Name	

Comment

OPG supports IESO’s comments.

Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

Southern Company believes that separating synchronous machine facilities from IBR facilities simplifies the complication that would exist by addressing both types of facilities in the same standard. While the existing "legacy" facilities have demonstrated imperfect ride-through performance (reactions) during system initiated disturbances, Southern believes that the application of ride-through requirements should only be applicable to facilities designed, built, and commissioned after the development of such a standard. The existing "legacy" facilities were not designed or built to achieve the desired ride-through performance that is specified in PRC-029-1, requirements R1-R5 of this proposed standard, and should not be subject to those requirements. The demonstrated performance, while not matching the ideal performance dictated by this proposed standard, is not catastrophic to the interconnection. The notion that generator owners have not taken any actions to improve the reaction of the legacy facilities to system disturbances is false. Southern Company has reviewed and modified control and protection settings for inverter operations at multiple facilities since the issuance of the first two NERC Alerts on the Loss of Solar facilities and during the multiple disturbance analysis evaluations. Addressing the desired performance with new facilities which will have the component design and control strategies sufficient to meet the desired performance should be a measure adequate to address the frequency control, voltage control, and stability needs and concerns of the interconnection.

Perhaps a more reasonable approach towards achieving better IBR facility ride through performance during system disturbance events, is to require evaluations with every instance of a plant output hiccup. The proposed required evaluation process in PRC-030, requiring corrective action plans to minimize/eliminate/eradicate the reason for the hiccup, would address, where possible, action taken through control or protection system setting changes, or through hardware changes - for equipment placed in service after the effective date of this draft standard).

Southern would offer general concerns with synchronizing language across all draft standards. For example, M1 states: *"shall have evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements"*. This seems like an opportunity to clarify by explicitly referencing standard(s) addressing data collection. This example repeats in some form in each "M" paragraph. Should the evidence of actual recorded data in M1 and other measures synch up with the phased in approach to PRC-028?

Finally, Southern Company supports EEI and NAGF comments.

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	Yes
Document Name	

Comment

NextEra aligns with EEI's comments:

EEI supports the development of a new Reliability Standard to address gaps in Inverter-Based Resource Performance and while the SAR does not include any language that specifically addresses FERC Order No. 901, EEI has no concerns with the SDT adjusting PRC-029 in line with the directives contained in this Order.

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	Yes
Document Name	

Comment

PG&E agrees with creating the new Standard PRC-029-1 to address IBRs.

Likes 0	

Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI comments	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Thank you for leaning heavily on IEEE 2800.	
Likes 0	
Dislikes 0	
Response	
Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting	
Answer	Yes
Document Name	
Comment	
Yes, generator ride-through is an essential reliability service and the changing generation technology to inverter-based has led to the need for improved, applicable, appropriate, and technically accurate requirements that suit IBRs. However, it is critically important that the implementation of these requirements consider all stakeholder needs and capture important technical considerations so that the requirements sufficiently mitigate risks without causing unnecessary costs or burdens on any responsible entity.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Brytowski - Great River Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brittany Millard - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
George E Brown - Pattern Operators LP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shonda McCain - Omaha Public Power District - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katrina Lyons - Georgia System Operations Corporation - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darcy O'Connell - California ISO - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Wesley Yeomans - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	2020-02_EPRI Comments on Draft NERC PRC-029 (IBR ride-through) Reliability Standard.pdf
Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you agree that the language within PRC-029-1 requirements R1, R2, and R6 regarding IBR plant-level performance during grid voltage disturbances is clear?

Darcy O'Connell - California ISO - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee	
Answer	No
Document Name	
Comment	

The ISO/RTO Council (IRC) Standards Review Committee (SRC) recommends the following modifications to improve the clarity and better convey the intent of the standard.

Recommended changes to R1:

"…as specified in Attachment 1 except when needed to clear a fault or a documented **and communicated** equipment limitation exists in accordance with **Requirement R6."**

Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that each IBR remains electrically connected and continues to exchange current in accordance with the no-trip zones and operation regions as specified in Attachment 1 unless needed to clear a fault or a documented equipment limitation exists in accordance with Requirement R6.

Recommended changes to M1:

"…demonstrating adherence to ride-through requirements, as specified in Requirement R1**, or shall have evidence of a documented and communicated equipment limitation, as specified in Requirement R6**."

Recommended changes to R2:

"…each IBR's voltage performance adheres to the following, unless a documented **and communicated** equipment limitation exists…"

The SRC recommends that the SDT to review and align the data in **Attachment 1** to ensure that the data in Tables 1 and 2 aligns with what is shown in Figures 1 and 2. Currently, the graphs in Figures 1 and 2 do not match what is indicated in the Tables. For example, rows 1-3 in Tables 1 and 2 are identical, yet Figure 2 does not match Figure 1 by indicating a Voltage Ride-Through Requirement of 1.0.

It appears that the SDT's intent is to require continuous operation between 95% and 105% voltage with a minimum ride-through time of at least 1800 seconds (half an hour) when voltage is above 105% and not exceeding 110%. If the intent is actually that equipment must be able to operate *continuously* at voltages up to 110%, then the tables and plots should be labelled with a descriptor that clearly indicates that indefinite or continuous operation is required rather than operation for a minimum ride-through time (1800 seconds). For example, a version of Table 2 that achieves the SDT's apparent intent could look like the following:

Voltage (per unit)	**Minimum Ride-Through Time (sec)**
>1.2	N/A

<=1.2 and >1.1	1.0
<=1.1 and >1.05	1800
<=1.05 and >=0.95	Continuous
<0.95 and >=0.90	Continuous*

*current limitation permitted, with active or reactive power preference as specified

<0.90 and >=0.70	6
<0.70 and >=0.50	3
<0.50 and >=0.25	1.2
<0.25	0.32

While the above comments point out areas of ambiguity in the draft standard that need to be clarified, the SRC recommends that Table 1 and Table 2 be modified to require IBR plants remain connected indefinitely when the voltage is between 1.05 and 1.1 pu. The current draft standard requires units to remain online for 1800 seconds in this range, and the logic behind this threshold is not clear. The current PRC-024 standard requires units to remain on-line indefinitely for the above range. [*All SRC entities support the comments in this paragraph except MISO*].

In addition, the SRC recommends a part be added to the standard to directly address the Permissive Operating Region, similar to what is done in Part 2.1 (for the Continuous Operation Region) and Part 2.2 (for the Mandatory Operation Region) as, the rules surrounding the Permissive Operating Region are unclear if this is not addressed. For example, there should be some linkage between the body of the standard and Attachment 1, item 10. The SRC proposes the following language for consideration (new Part 2.3):

2.3 While voltage at the high-side of the main power transformer is within the Permissive Operation Region as specified in Attachment 1, an IBR may operate in current block mode only if necessary to protect the equipment. Otherwise, each IBR shall follow the requirements for the Mandatory Operation Region in Requirement R2, Part 2.2.

Recommended changes to R6:

The SRC is concerned that Requirement R6 as proposed provides an overly broad exemption, as the standard is silent as to what criteria must be met to qualify for an exemption and contains no requirement that a Corrective Action Plan be developed or that the equipment limitations be resolved or addressed. Only notification to other entities is required. The SRC recommends that the SDT:

- Develop more specific criteria as to what qualifies as an equipment limitation[1], OR A technical justification that addresses why corrective actions will not be applied nor implemented.
- Require exemptions be submitted to NERC and/or the Regional Entities for pre-approval in order to qualify for the exemption.

The SRC suggests there should be explicit requirements to both 'document equipment limitations' and to 'communicate' those documented limitations to the appropriate parties. The SRC proposes the following modifications to address this issue:

"Each Generator Owner and Transmission Owner with a **known** equipment limitation that would prevent an applicable IBR that is in-service by the effective date of this standard from meeting voltage ride-through requirements as detailed in Requirements R1 and R2 shall **document** each equipment limitation, develop a Corrective Action Plan to address the limitation, **and communicate both the limitation and the Corrective Action Plan** to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s).

Recommended changes to M6:

Each Generator Owner and Transmission Owner shall have evidence of **known** equipment Limitations accompanied by a Corrective Action Plan, as specified in Requirement R6, **having been** documented **and communicated** to each associated Planning Coordinator, Transmission Planner, and Reliability Coordinator prior to the effective date of PRC-029-1.

Each Generator Owner and Transmission Owner with changes to equipment shall have evidence of communication to each associated Planning Coordinator, Transmission Planner, and Reliability Coordinator.

[1] *See Implementation Plan (page 4), "only those IBR that are unable to meet voltage ride-through requirements due to their inability to modify their coordinated protection and control settings may be considered for potential exemption." See Technical Rationale (page 9); i.e. specify which voltage band(s) and associated duration(s) cannot be satisfied or specific as to the number of cumulative voltage deviations within a ten-second time period that the equipment can ride-through if less than four… identify the specific equipment and explain the characteristic(s) of that equipment that prevent ride-through.*

Likes 0	
Dislikes 0	

Response

Michael Brytowski - Great River Energy - 3

Answer	No
Document Name	Attachment 1 figures 1 and 2 .pdf

Comment

Comments: GRE requests the SDT review and align the data in **Attachment 1** so the data in Tables 1 and 2 aligns with what is shownin Figures 1 and 2. Currently, the graphs in Figures 1 and 2 do not match what is indicated in the Tables. (uploaded)

GRE recommends a part be added to the standard to directly address the Permissive Operating Region, similar to what is done in Part 2.1 (for Continuous Operation Region) and Part 2.2 (for Mandatory Operation Region) as, if left unaddressed, is unclear. For example, there should be some linkage between the body of the standard and Attachment 1, item 10. MRO NSRF proposes the following language for consideration (*new* Part 2.3):

2.3 While voltage at the high-side of the main power transformer is within the Permissive Operation Region as specified in Attachment 1, an IBR may operate in current block mode only if necessary to protect the equipment. Otherwise, each IBR shall follow the requirements for the Mandatory Operation Region in Requirement R2.2.

GRE is concerned that requirement R6 provides an overly broad exemption as written as the standard is silent as to what criteria must be met. Only notification to other reliability entities is required with no requirement to develop and implement a Corrective Action Plan. MRO NSRF recommends the SDT:

Develop more specific criteria as to what qualifies as an equipment limitation[1], OR

Require exemptions be submitted to NERC and/or the Regional Entities for approval in order to qualify for the exemption.

[1] *See Implementation Plan (page 4), i.e. "only those IBR that are unable to meet voltage ride-through requirements due to their inability to modify their coordinated protection and control settings may be considered for potential exemption." See Technical Rationale (page 9); i.e. specify which voltage band(s) and associated duration(s) cannot be satisfied or specific as to the number of cumulative voltage deviations within a ten-second time period that the equipment can ride-through if less than four… identify the specific equipment and explain the characteristic(s) of that equipment that prevent ride-through.*

R2: GRE agrees with the present flexibility that some of the IBR VRT performance could be modified to meet the individual system needs by the applicable Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator. However, some clarity may be required on how this process is initiated and what type is evidence is required to demonstrate request is received and implemented. This may be an additional requirement assigned to the Transmission Planner. Each Transmission Planner, Planning Coordinator, and Transmission Operator that jointly specifies the following voltage ride-through performance requirements within their area(s) different than those specified under R2, shall make those requirements available to each associated applicable IBR Generator Owner and Transmission Owner.

Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	No
Document Name	
Comment	
See comments below under question 4.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	

Comment	
R2.5 & R5.1, et al. Each IBR shall only trip … "Trip" may be ambiguous. Does this mean disconnecting from the system to de-energize the IBR equipment, as in opening a circuit breaker? Or does it mean cease exchanging current? Or something else?	
Likes 0	
Dislikes 0	
Response	

John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
For R1, We recommend adding language to refer to plants that were previously exchanging current before the disturbance. For example, A BESS that is fully charged would be connected to the BES, but would not be exchanging current. For R2, change "each IBR's voltage performance" to voltage ride through performance. For R6, exemptions should not be automatically allowed. This would allow for bad designs relying on an exemption. Exemptions should only be for existing or legacy units. New units should not have the option for exemption.	
Likes 0	
Dislikes 0	
Response	

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	No
Document Name	
Comment	
Southwest Power Pool joins the ISO/RTO Council Standards Review Committee comments.	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No

Document Name	

Comment

In the opinion of ACES, the newly proposed Glossary Terms are unnecessary and seemingly incongruous terms. For example, if the Mandatory Operating Region is required, should it not also be continuous? It is our opinion that these terms add little to no value and instead only create confusion where none was previously present. We recommend striking these new terms from the standard.

In ACES' opinion, R1 appears to be overly broad so as to require an applicable IBR to be operational at all times. This does not appear to allow for full facility outages without first having a "documented equipment limitation" per R6. Thus, as written, the GO will run the risk of non-compliance with either R1, R6, or both whenever a full facility outage of an IBR is required. Furthermore, it is unclear how R1 differs from R2 other than seeming to requiring the GO to ensure the GOP always keeps the unit online during to normal operation. We recommend striking R1 from the standard.

Additionally, we do not agree with the language of Requirement R2, Part 2.1.1. As written, R2 does not define what type of System disturbance is applicable and Part 2.1.1 requires the GO to continue producing active power at the pre-disturbance levels or its maximum capability; whichever is less. We have concerns with this approach. Namely, during an over frequency deviation event wherein the high side MPT voltage remains ≥ 0.9 p.u. and ≤ 1.1 p.u. In this instance, the frequency response algorithm within the IBR would attempt to reduce active power output. Due to the fast-acting nature of IBRs, it is likely that an IBR facility(ies) would respond to and correct such an event before a synchronous generating resource(s). However, in the aforementioned hypothetical example, to comply with R2.1.1, the IBR frequency response control would need to be either disabled or limited in its response to an over frequency System disturbance. In our opinion, this is not beneficial to the reliability of the BES. While possibly unlikely at the current time, this hypothetical scenario becomes increasingly likely as conventional synchronous generating resources are retired in favor of IBRs.

Furthermore, it is the opinion of ACES that R6 should be modified to include any potential regulatory limitations. This suggested approach is in line with the approach taken in PRC-024-4 R3. We recommend the modifying R6 as follows:

R6. Each Generator Owner and Transmission Owner shall document each known regulatory or equipment limitation that prevents an applicable IBR that is in-service by the effective date of this standard from meeting voltage or frequency ride-through requirements as detailed in Requirements R1 through R5.

6.1 Each Generator Owner and Transmission Owner shall include in its documentation:

6.1.1 Identifying information of the IBR (name, facility #, other)

6.1.2 Which aspects of voltage ride-through requirements that the IBR would be unable to meet

6.1.3 Identify the specific piece(s) of equipment causing the limitation.

6.2 The Generator Owner and Transmission 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, and Reliability Coordinator within 30 calendar days of any of the following:

6.2.1 Identification of a regulatory or equipment limitation.

6.2.2 Repair of the equipment causing the limitation that removes the limitation.

6.2.3 Replacement of the equipment causing the limitation with equipment that removes the limitation.

Lastly, the values specified in Table 1 and Table 2 in Attachment 1 do not align with the graphs shown in Figure 1 and Figure 2, respectively.

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	No
Document Name	

Comment

See comments submitted by Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

See EEI comments

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	No
Document Name	

Comment

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

Electric Reliability Council of Texas, Inc. (ERCOT) joins the comments of the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own in addition to the following comments, except to the extent of any specific differences between the SRC comments and the following comments from ERCOT.

As detailed below, the currently proposed language for Requirement R1 is not clear. Additionally, ERCOT believes that plant-level requirements are insufficient because individual IBR unit performance failures continue to occur and could, in aggregate, be just as impactful or more impactful than the complete loss of an IBR plant. The performance threshold should be coordinated with the threshold in PRC-030, and ERCOT believes a reasonable threshold would be the **lesser** of either 20% of the plant's gross nameplate rating, or 20 MW. In an IBR-dominated electric system, these aggregated losses could cause unreliable operations if not corrected. The past 8-10 years have demonstrated that IBR owners will not voluntarily correct these performance issues in the absence of a mandatory reliability standard.

SDT's proposed language (ERCOT finds the bold portions unclear):

"Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that **each IBR** remains electrically connected and continues to exchange current in accordance with the no-trip zones and operation regions as specified in Attachment 1 unless **needed** to clear a fault or a documented equipment limitation exists in accordance with Requirement R6."

ERCOT's proposed language:

"Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that each IBR, **and its IBR units**, remains electrically connected and continues to exchange current in accordance with the no-trip zones and operation regions as specified in Attachment 1 unless **the IBR, or its IBR units, needs to be tripped** to clear a fault or a documented equipment limitation exists in accordance with Requirement R6."

In addition to the concerns with Requirement R1 noted above, ERCOT is concerned that Requirement R2 does not clarify the timeframe encompassed by the term "System disturbance." Without further clarification, "System disturbance" may be interpreted to only describe the fault itself, even though control instability may manifest itself immediately after the fault clears or during the milliseconds or seconds after the fault clears, during which time frequency and voltage support are still critical. While IEEE 2800 defines the disturbance period, and there is an expectation that an IBR will perform acceptably in the continuous operation region, Requirement R2 is not clear that "riding-through" a disturbance includes both the fault and the non-fault portions of the disturbance along with the transition from ride-through mode to a new steady-state (i.e., the post-disturbance period). ERCOT suggests a 10-second window as a bright-line criterion.

SDT's proposed language for Requirement R2.

"R2. Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that during a System disturbance, each IBR's voltage performance adheres to the following, unless a documented equipment limitation exists in accordance with Requirement R6."

ERCOT's proposed language for Requirement R2:

"R2. Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that during, **and up to ten seconds after,** a System disturbance, each IBR's voltage performance **and its associated IBR units'** voltage performance adheres to the following, unless a documented equipment limitation exists in accordance with Requirement R6."

For Requirement R2, Part 2.2.2, ERCOT agrees that location-specific flexibility may be needed and defined by the TP, PC, RC, and or TOP; however, the language should clearly mandate that in such instances, the established performance requirements must also be met. Additionally, the current wording does not address the possibility that reactive current "response" could be in the wrong direction if not properly configured, and the language should be clarified to address this issue. ERCOT proposes the following language for Part 2.2.2 to capture the full spectrum of current priority modes from full aggressive reactive priority mode, to a de-tuned reactive response while in reactive priority mode, to an active priority mode.

"Adjust reactive current injection at the high-side of the main power transformer so that the magnitude of the reactive current **properly** responds to changes in voltage at the high-side of the main power transformer in accordance with default reactive prioritization **or as required by** any applicable Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator **that specifies** a certain magnitude **and timeliness** of reactive power response to voltage changes, **that specifies a maximum allowed active current reduction to provide reactive current, or that specifies** active power priority instead of reactive power priority."

ERCOT also recommends including the following language to help prevent unnecessary misoperations due to the use of unfiltered measurements or instantaneous (no time delay) settings for protection systems, consistent with NERC recommendations for addressing easily preventable performance failures.

R2.2.3 "Utilize sufficient time delays or filtering methods for any voltage measurements utilized by its protection equipment to prevent unnecessary trips due to calculation errors or transients."

ERCOT finds the bolded portions of the SDT's proposed language for Requirement R2, Part 2.3 to be unclear:

"The IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable Attachment 1 Table 1 or Table 2 no-trip zone voltage thresholds and time durations **in its response from** Mandatory or Permissive Operation Regions to the Continuous Operating Region."

ERCOT proposes the following language to clarify the issue:

"The IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable Attachment 1 Table 1 or Table 2 no-trip zone voltage thresholds and time durations **in its response as it transitions from** Mandatory or Permissive Operation Regions to the Continuous Operating Region."

ERCOT would also point out that the last clause may not be necessary because the IBR should not cause high voltage at any time, and the SDT could consider the following alternative language:

"The IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable Attachment 1 Table 1 or Table 2 no-trip zone voltage thresholds and time durations."

Consistent with the comments above on Requirement R2, Part 2.2.2, Requirement R2, Part 2.4 should be revised as follows to clarify that the other requirements or specifications from the RC/PC/TP/TOP must still be met:

"Each IBR shall restore active power output to the pre-disturbance or available level within 1.0 second when the voltage at the high-side of the main power transformer returns to the Continuous Operation Region from the Mandatory Operation Region or Permissive Operation Region (including operation in current block mode) as specified in Attachment 1, **or as required** by any applicable Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator **that specifies** a lower post-disturbance active power level requirement or **that specifies** a different post-disturbance active power restoration time."

Requirement R2, Part 2.5 may not be clear, in light of the new defined terms, that partial trips (including trips of individual IBR units) should not be allowed. While this topic should be coordinated with PRC-030, it goes to the heart of momentary cessation in that staying connected but not supporting frequency and voltage can, in aggregate, be just as detrimental to reliability as a full trip. The SDT should consider revising Part 2.5 to ensure that it is clear that there would be a violation at a particular level (e.g., the lesser of 20% of the unit's rated output, or 20 MW) of IBR unit trips. This could be graduated in severity level starting at the 20% or 20 MW level and increasing thereafter (e.g., 20%, 40%, 60%, 80%, and above).

ERCOT's proposed language for Part 2.5: "Each IBR, **or its IBR units,** shall only trip to prevent equipment damage, when the voltage at the high-side of the main power transformer is outside of the no-trip zone as specified in Attachment 1."

ERCOT also has concerns with the SDT's proposed Requirement R6 language:

"Each Generator Owner and Transmission Owner with **a documented equipment limitation** that would prevent an applicable IBR that is in-service by the effective date of this standard from meeting voltage ride-through requirements as detailed in Requirements R1 and R2 **shall communicate each equipment limitation to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s).**"

More specifically, the first bolded phrase ("a documented equipment limitation") appears to allow complete GO/TO discretion to declare a limitation with no process for review, approval, or acceptance of the limitation by any other entity. Only a communication to the PC, TP, and RC is required. It is unclear if the SDT's intention is that at some point these documented limitations would be reviewed or evaluated under the NERC CMEP (and it is unclear what standard the limitation documentation would be held to under such a review). At a minimum, Measure M6 and/or the Technical Rationale should provide more information about what an acceptable limitation might be and guidance for CMEP staff to use in evaluating the validity of limitations and the associated documentation.

The second bolded portion ("shall communicate each equipment limitation to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s)") is necessary, but may not be effective from a reliability perspective. A mere description of a limitation sent in an email or letter would not be useful for the PC/TP/RC but would meet the letter of Requirement R6. If the purpose of the communication is for PCs, TPs, and RCs to be able to assess the limitation and incorporate it into system studies, either Requirement R6 or the Technical Rationale should clarify that the communication needs to be in a format that is acceptable and useful to the PC/TP/RC (most likely in the form of an updated model that reflects the limitation). Additional burdensome administrative requirements to cover this communication process are not suggested, but at the very least the Technical Rationale should include guidance and set expectations to ensure that the communication will be useful to ensure the reliability of the grid. Additionally, ERCOT notes that FERC Order 901 recognized that "a subset of existing registered IBRs – typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements directed herein." ERCOT recommends that Requirement R6 be clarified to indicate that the equipment limitation process is only available to the limited subset of IBRs described in Order 901.

Additionally, ERCOT notes that Requirement R6, Part 6.2 does not require the TO/GO to actually improve ride-through capability even when equipment is replaced:

"Each Generator Owner and Transmission Owner with a previously communicated equipment limitation that repairs or replaces the equipment causing the limitation shall document and communicate such equipment changes to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s) within 30 days of the equipment change."

Rather than focusing on communication of changes, Part 6.2 should require the TO/GO to comply with all PRC-029 requirements and should not allow any documented limitations whenever equipment is changed or replaced; this approach would better align with FERC Order 901. PRC-029 should also include a requirement that mandates the implementation of software settings changes and upgrades (that do not require replacement of physical equipment) that improve ride-through capability. This is referenced in the implementation plan, but is absent from the actual requirements in PRC-029.

Equipment limitations may also not be currently captured in dynamic models, and the list of requirements should be updated to reflect this issue. The MOD standards may not accurately account for the provision of this information to all entities that perform studies (including stability limit and IROL determination studies that RCs perform); this would constitute a reliability gap. RCs and PC/TPs must be able to assess the impact of these exemptions to be able address the reliability impact under FERC Order 901.

Finally, ERCOT notes that FERC Order 901 requires NERC to "determine whether the new or modified Reliability Standards should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements. Any such exemption should be only for voltage ride-through performance for those existing IBRs that are unable to modify their coordinated protection and control settings to meet the requirements without physical modification of the IBRs' equipment." While it is clear that the SDT has determined that the standard should allow for documented exemptions for equipment limitations, the requirement language is unclear as to how or whether this exemption process is truly "limited" as required in Order 901, especially in light of the explicit reference to IBRs "that are *unable* to modify their coordinated protection and control settings to meet the requirements without physical modification of the IBRs' equipment." As ERCOT notes below, exemptions should be limited to scenarios where a responsible entity cannot otherwise achieve the necessary ride-through performance without physical equipment changes (inability to meet ride-through requirements that can be addressed simply by making software- or parameterization-type changes should not be grounds for an exemption) OR to scenarios where, even without making the remaining physical changes, the loss of a contingency would not cause instability, Cascading Outages, or uncontrolled separation that adversely impact the BPS.

Likes 0	
Dislikes 0	

Response

Shonda McCain - Omaha Public Power District - 6

Answer	No
Document Name	

Comment

OPPD supports comments provided by GRE: Michael Brytowski, Great River Energy, 3, 4/17/2024	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	No
Document Name	
Comment	

Requirement 1 and 2

These requirements mention that the IBRs should respond to the voltage changes with reactive current injection during a system disturbance, however, the magnitude of this response is not identified. The magnitude and expectation of the response should be clarified due to the fact that it can vary by unit and unit capabilities.

Measures 1, 2, 3, 4, and 5

With regards to data recording, it is unclear what counts as recording? If the expectation is the same as contained in PRC-028-01 Draft 2, that should be specified; or otherwise identify alternate means of data recording.

What if an entity does not have a recorded event to show compliance with the standard and prove its ability to ride through a system event?

Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	

NextEra aligns with EEI's comments:

EEI agrees with most of the proposed language in Requirements R1, R2 and R6; however, the phrase “of an applicable IBR” should be removed. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant.

EEI also does not support Requirement R2, subpart 2.5 because it contains unneeded language, which adds confusion and implies that GOs can only trip outside of the trip zone if their equipment might become damaged. This has never been an obligation for synchronous generators, and we do not agree that this should be an obligation for IBRs. If NERC or the SDT believe that the no-trip zone needs to be expanded, they should justify such a change and present it for industry review and comment, otherwise, Requirement R2, subpart 2.5 should be deleted.

And while we support Requirement R6 and the provisions to notify PCs, TPs and RC about equipment limitations that would prevent an applicable IBR from meeting ride-through requirements as detailed in Requirements R1 and R2, the Requirement does not go far enough because there may be technical reasons why an applicable IBR is unable to meet Requirement R3 through R5, as well. To address this concern, R6 should be expanded to include Requirement R1 through R5.

Likes 0	
Dislikes 0	

Response

Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

In regard to R1:

Does M1 imply that actual recorded data must be kept as evidence of ride-thru compliance for every in-scope IBR, for every system disturbance? Thesame question applies to R2-M2, R3-M3, R4-M4, and R5-M5.

The disturbance characteristic must be specified in order to trigger captures of performance information for every disturbance at every IBR facility - the characteristic which defines each type of disturbance must be defined in order to capture the record.

For each of the Measures M1 - M5, what "other evidence" can demonstrate compliance with R1-R5 other than recorded data? How does the drafting team believe that generator owners can assure this performance expectation can be achieved prior to an actual event? There is no test verification that can be performed to confirm the expected performance. Consider providing some examples of what is acceptable as “other evidence”.

R1 mentions “operation regions specified in Attachment 1. R2, Part 2.1 mentions “continuous operation region as specified in Attachment 1” and Part 2.2 mentions “mandatory operation regions as specified in Attachment 1”. However, nowhere in attachment 1, is there mention of "continuous, mandatory, or permissive" operation regions.

In regard to R2:

For R2, Continuous Operation Region is not specified in Att. 1; it is merely a defined term in the draft standard. Southern Company suggests that the referenced region be shown on the graph of Att.1, or that the words from the defined term simply be placed in the sub-requirement directly rather than creating a defined term. The term region implies an area (volt-time). If the definition is simply specifying voltage level magnitude, simply state that. The definition labels are confusing; does permissive operation mean the IBR has permission to trip if the voltage is less than 0.1pu? It is observed that the values in the "mandatory operating region" match some of the borders of the "no trip zone" in Attachment 1, yet there is a time element that must be accounted for in determining if a trip is in compliance or not with the curve of Att. 1. For example, how can a long term (1-9 second) event where the voltage is 0.4pu be a Mandatory Operating Region? The voltage ride-thru curve does not specify this (for example).

Regarding the R2.2 and R2.3 requirement specifications, IBR facilities do not have per phase voltage regulation in their current designs, so the feasibility of successfully reacting to low system voltage (R2.2) with rapid reactive power injection while not possibly causing high voltage locally (R2.3) is questionable.

Regarding R2.1.1 & R2.1.2, it should also reference Interconnection Agreements (IA) limits since some IBR facilities have both solar and battery storage with an IA limit less than the aggregate sum.

Regarding R2.1.1 and R2.1.2, the idea that IBR Facility Power Plant Controllers operate to apparent power limits, is not in line with normal practices. Most PPC interfaces do not provide an apparent power reading or control function option. PPCs communicate separate MW and MVAR setpoints to all the of the site IBR Units and they follow or provide as capable the MWs and deliver MVARs up to the inverter reactive power limit.

Southern Company recommends changing wording to:

R2.1.1:Continue to deliver the predisturbance level of active power or available active power, whichever is less, and continue to deliver active p ower and reactive power up to its reactive power limit.

R2.1.2:If the IBR cannot deliver both active and reactive power due to a current or reactive power limit, when the applicable voltage is below 9 5% and still within the Continuous Operation Region, then preference shall be given to active or reactive power according to requirements spec ified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

R2.1.2 discusses giving preference to either active or reactive power based on requirements specified by transmission entities. There is some concern that this could be interpreted as a fluid preference that could require IBRs to actively configure active vs reactive capabilities.

Regarding R2.3, what happens if TOP has several lines down for maintenance in the area, which causes the part of the system the IBR facility is located, go from a strong system to a weak system?

R2.4 does not take into consideration other dynamic system conditions as a result of the fault and the effects on the PPC during a fault recovery. An example of this is Primary Frequency Response due to system frequency excursions during fault recovery. The active power recovery may be reduced or frozen during an underfrequency event while an IBR Resource is in recovery, thereby extending the time of the recovery.

R2 specifies performance for continuous and mandatory operation region, but not for permissive operation region. The performance during permissive operation region is in Attachment 1. Performance for all regions should be in Requirement R2.

Regarding R2.1.1, the first part, where IBR is required to continue to deliver the pre-disturbance level of active power or available active power, whichever is less is fine. However, the second part (and continue to deliver active power and reactive power up to its apparent power limit) is conflicting with the first part of this requirement. If the IBR plant's available active power was 50% of nameplate rating due availability of wind, solar irradiance, etc., then the second part of the requirement is stating that plant is required to produce reactive power to its apparent power limit given its available active power equal to 50% of nameplate rating. This is not correct.

In regard to R2.1, the clause 7.2.2.2 of the IEEE Std 2800 includes an exception when negative-sequence voltage is higher than certain threshold for a given time duration. Why the SDT not include this exception in the PRC-029?

In regard to R2.2, it appears the intent is to require that inject balanced current, during symmetrical faults, and unbalanced current during asymmetrical faults. However, the language is confusing. First, there is no plant level voltage regulation during a fault condition. Second, during unbalanced faults, what does a voltage regulation mean? One option is replace both Part 2.2.1 and Part 2.2.2 with following: The IBR shall inject current based on voltage deviation on high-side of main power transformer and as specified by the TP, PC, RC, or TOP.

In regard to R2.3,this requirement is confusing. Table 1 and 2 in Attachment 1 includes both low- and high-voltage thresholds. One meaning could be that the IBR shall not cause voltage to exceed LVRT threshold for a specified time duration. The true meaning is unclear. Is it correct that the intent is to focus on HVRT thresholds and time duration? The time duration for voltage > 1.2 per unit is not specified. Does this mean that IBR shall not cause overvoltage > 1.2 per unit whatsoever? If so, it needs to be written clearly.

In regard toR2.5, if there is no expectation for IBR to ride-through disturbance outside of no-trip zone, then there is no need for this requirement. For example, if voltage is zero for greater than specified time duration in Tables 1 and 2, say 1 second, then what is the point in staying connected and feeding into fault unless there is a risk of equipment damage? Additionally, there is no such expectation for frequency ride-through requirement R4.

R2.5 is not practical for the GO to determine where every individual piece of equipment would be damaged. There is no need to require tripping just before equipment damage if IEEE 2800 is guidance for equipment manufacturers.

In regard to Attachment 1:

1. There is no mention of continuous, mandatory, or permissive operation region in tables 1 and 2. Consider adding a column in tables 1 and 2 to show these operation regions.
2. For Table 1 and 2:
    - ≥1.20 should be >1.2
    - ≥1.1 should be >1.1
    - ≥1.05 should be >1.5
3. In IEEE Std 2800, the cumulative ride-through duration of 1800 second when voltage is > 1.05 is applicable to all nominal voltages except for 500kV nominal operating voltage. For 500kV nominal operating voltage, the equipment rated to 550kV (1.10 per unit) is available per ANSI C84.1. In IEEE Std 2800, see Note 1 under Table 12. Consider clarifying this in the PRC-029.
4. Note 7: A time window of 10-second is mentioned. However, when V>1.05, the ride-through duration is 1800 second, which is over a 3600-second time window in IEEE 2800.
5. Note 10: The purpose of current blocking in IEEE 2800 was not to protect the equipment but to rather to avoid tripping due to consequences of injecting current and hence, failure of ride-through.
6. Figures 1 & 2: why does the X-axis start at 0.1 second and not zero?

Finally, Southern Company supports EEI and NAGF comments.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	No
Document Name	
Comment	
In 2.1.1 the "apparent power limit" is what is capable during the System disturbance correct? What is the "applicable voltage" to determine 95% in 2.1.2 (and why is per unit not used)? Where are the "requirements specified" by the TP/PC/RC/TOP and how does a GO or TO determine which one to use? If in the Planning world, the requirements should be specified in the TPL Standards. It is unclear what actions a TO/GO will take and be consistently applied. Since this is an event driven compliance review in the Operations Assessment time horizon, why would a TP or PC provide preference for active or reactive power in that timeframe? In a response study by the TP/PC, perhaps guidance on preference could be provided but it is unclear and NOT required in TPL Standards to this point. Clarity between the Tables and Figures in Attachment one needs provided to avoid confusion. Just to be clear, It appears that any new units after the effective date of this Standard have to meet all the criteria. Do the existing units with limitations have six months after the effective date of Standard to submit equipment limitations. With PRC-024-3 and PRC-024-2 already having a Requirement in place that requires limitations to be provided to the TP/PC and the industry already leaning on IRO-010 and TOP-003 for notifications, why is there a need to add an additional 6 months for Requirement R6? The RC already has communication capability with GOs.	
Likes 0	
Dislikes 0	
Response	

Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	

Comment

R1:

R1 should be revised to directly clarify, or include a footnote to clarify, the statement “that each IBR remains electrically connected and continues to exchange current” with “electrically connected, i.e., shall not trip, and continue to exchange current, i.e., shall not enter momentary cessation” that was provided in the Technical Rationale.

Attachment 1:

There is a discrepancy between the definition of the Term “Mandatory Operating Region” which states “≤ 1.2 per unit” and Table 1/Figure 1 or Table 2/Figure 2 which state “≥1.200” per unit “N/A”. Please clarify if Table 1/Figure 1 and Table 2/Figure 2 should state “>1200” or if the definition of the Term “Mandatory Operating Region” should state “<1.2 per unit”.

Please clarify Figure 1 and Figure 2 to clearly show the “Continuous Operating Region”, “Mandatory Operating Region”, and “Permissive Operating Region”, along with requirements beyond 10 seconds.

Please Clarify “9. The IBR may trip for more than four deviations of the applicable voltage….” In attachment 1.

R2.5:

This requirement is beyond the purpose of the standard, which is to establish Frequency and Voltage Ride-through Requirements for Inverter - Based Generating Resources and should be removed.

Likes 0	
Dislikes 0	

Response

Dave Krueger - SERC Reliability Corporation - 10

Answer	No
Document Name	

Comment

On behalf of the SERC Generator Working Group:

R2.4 does not take into consideration other dynamic system conditions as a result of the fault and the effects they can have on the PPC during a fault recovery. An example of this is Primary Frequency Response due to system frequency excursions during fault recovery. The active power recovery may be reduced or frozen during an over-frequency event while an IBR Resource is in recovery, thereby extending the time of the full recovery.

R2.5: It is not practical for the GO to determine where every individual piece of equipment would be damaged, nor should the GO be required to subject equipment to failure by trying to identify that point, run to it, and risk damaging it.

Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG supports IESO's comments.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
EEI agrees with most of the proposed language in Requirements R1, R2 and R6; however, the phrase "of an applicable IBR" should be removed. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant. EEI also does not support Requirement R2, subpart 2.5 because it contains unneeded language, which adds confusion and implies that GOs can only trip outside of the trip zone if their equipment might become damaged. This has never been an obligation for synchronous generators, and we do not agree that this should be an obligation for IBRs. If NERC or the SDT believe that the no-trip zone needs to be expanded, they should justify such a change and present it for industry review and comment, otherwise, Requirement R2, subpart 2.5 should be deleted. And while we support Requirement R6 and the provisions to notify PCs, TPs and RC about equipment limitations that would prevent an applicable IBR from meeting ride-through requirements as detailed in Requirements R1 and R2, the Requirement does not go far enough because there may be technical reasons why an applicable IBR is unable to meet Requirement R3 through R5, as well. To address this concern, R6 should be expanded to include Requirement R1 through R5.	
Likes 0	
Dislikes 0	
Response	

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	No
Document Name	
Comment	
Vistra agrees with Invenergy	
Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power (MP) agrees with the MRO NSRF's comments on R1, R2, and R6, and the associated graphics from Attachment 1. Additionally, MP notes that language from the Technical Rationale document specifies that R2.1, R2.3, and R2.4 are intended to apply when system conditions return to the Continuous Operation Region from the Mandatory or Permissive Operation regions. This should be specified in the standard. Finally, MP proposes the following language changes to eliminate any possible uncertainty: Section 2.1: "current or apparent power limit" to "current limit or apparent power limit" Section 2.4: "pre-disturbance or available level" to "pre-disturbance level or available level, whichever is lesser"	
Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	

Constellation does not agree and feels the HVRT times are very high. Many wind turbines/inverters won't be able to meet those times, equipment in general and these systems have not been designed to withstand that much overvoltage.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Maozhong Gong - GE - GE Wind - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

For R6, R3,R4,R5 should be included as well for the documented limitation communication (see R6 comments below)

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	No
Document Name	

Comment

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Imane Mrini - Austin Energy - 6, Group Name Austin Energy

Answer	No
Document Name	

Comment

AE supports comments provided by Texas RE and the NAGF

Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI agrees with most of the proposed language in Requirements R1, R2 and R6; however, the phrase “of an applicable IBR” should be removed. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant.

EEI also does not support Requirement R2, subpart 2.5 because it contains unneeded language, which adds confusion and implies that GOs can only trip outside of the trip zone if their equipment might become damaged. This has never been an obligation for synchronous generators, and we do not agree that this should be an obligation for IBRs.   If NERC or the SDT believe that the no-trip zone needs to be expanded, they should justify such a change and present it for industry review and comment, otherwise, Requirement R2, subpart 2.5 should be deleted.

And while we support Requirement R6 and the provisions to notify PCs, TPs and RC about equipment limitations that would prevent an applicable IBR from meeting ride-through requirements as detailed in Requirements R1 and R2, the Requirement does not go far enough because there may be technical reasons why an applicable IBR is unable to meet Requirement R3 through R5, as well. To address this concern, R6 should be expanded to include Requirement R1 through R5.

Likes 0	
Dislikes 0	
Response	

Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	

R1/R2: Recommend that Attachment 1 have a chart to include the Continuous Operation Region, Mandatory Operation Region, and Permissive Operation Region or have those regions specified on existing Voltage Ride -through Requirements Figure 1 and Figure 2.

Requests the SDT review and align the data in **Attachment 1** so the data in Tables 1 and 2 aligns with what is shown in Figures 1 and 2. Currently, the graphs in Figures 1 and 2 do not match what is indicated in the Tables.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

Duke Energy recommends the implementation of EEI and NAGF comments.

Duke Energy does not agree that the language is clear. The language seems close to but not completely in alignment with IEEE 2800-2022. It is not clear that the -029 requirements align with the IEEE 2800 requirements, especially given that most would want to comply with both. Many times the Continuous Operation Region is associated with the voltage regulation function and the Mandatory Operation Region is associated with LVRT. This separation is not maintained in various statements within 2.1 and 2.2. It is not clear how the plant or inverters can be configured to operate as specified in R2. Overall the language seems overly prescriptive and the DT may consider less specificity and possibly even a reference to IEEE 2800 rather than trying to restate it. Voltage regulation functions are typically based on POI voltage while LVRT functions are based on inverter terminal voltage. It is not clear that the requirements recognize this difference.

Also, there are multiple references in R1 and R2 to Attachment 1 containing or representing the various Regions, but they are not graphically represented. The DT may consider revising the Att. 1 Figures (and moving the vertical axis crossing to 0.1 sec).

tt seems the industry has often misinterpreted the area outside of the No-trip Zone as an area where the plant must trip. The DT may consider specifically addressing and emphasizing in the text and on the Figure that the plant is not required to trip in this area. For example, it may be labeled May Trip Zone. To that end, it would also be helpful for the GO to submit equipment ride through limits. That is the actual equipment limits, not the various voltage protection settings. With that information, plants would have the bases to provide the maximum ride-through beyond the No-Trip Zone and still not exceed plant main and BOP equipment limits.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

WEC Energy Group does not agree that the language in R1, R2, and R6 is clear for the following reasons:

R1.:

WEC disagrees with text "… shall ensure that each IBR remains connected…". How else can an entity "ensure" to remain connected other than to set voltage protection outside the no-trip zone? The requirement must state what must be done. Based on Attachment 1, this is clearly voltage protection settings function so R1 should try and match PRC-024 R1. Otherwise, this requirement is open-ended as IBR could potentially be disconnected due to other reasons and the entity will be deemed non-compliant.

The "main power transformer" should be defined in a footnote, similar to what's proposed in PRC-028. It's unclear if main power transformer represents individual IBR step-up transformer or the site step-up transformer.

The phrase "exchange current" should be listed and defined in Terms section. Confusion exists in understanding if "exchange current" applies to BESS while charging, real/reactive current components, or something else. An exception should be added to exclude BESS from the PRC-029 requirements while charging.

WEC also disagrees with M1. The only means for an entity to "ensure IBR remains connected" is to set voltage protection and voltage ride-through protection according to Attachment 1. Making sure that the settings are applied should be the measure. The "recorded data" is an inconclusive statement. If the entity applied settings outside the no-trip zone and it still tripped, which could be for various other reasons, does that mean then entity is non-compliant? What needs to be recorded and where? Does this measure now mandate additional recording capabilities in addition to PRC-030? (Same comment applies to M2, M3, and M4).

R2.:

WEC disagrees with text "…. shall ensure that each IBR remains connected…". The requirement must state what TO and GO must do. Otherwise, this requirement is open-ended without a measurable statement.

2.1: Term "Continuous Operating Region" as defined conflicts with equipment design limitations. Power transformers may not be designed for continuous operations from 0.9 and 1.1 pu. Please refer to IEEE C57.12.00, sections 4.1.6.1, 4.1.6.2 and 5.5, and ANSI C84.1. Without some specific maximum time applied, the continuous operating region will conflict with equipment limitations. Due to this wide range, entities will simply take exception to R2 and R2 will not have any positive benefit for BES reliability. There is a reason PRC-024-3 has a 4 second limit. This limitation should clearly be introduced in PRC-029. Finally, the proposed "Continuous Operating Region" range conflicts with acceptable continuous operating ranges by Transmission Operators. Many Transmission Operators classify continuous operating range from 0.95 and 1.05 pu, and consider voltage ranges from 0.9 to 0.95 pu and 1.05 to 1.1 pu as abnormal voltage ranges.

2.1.2: There is nothing that governs a TP, PC, RC or TO to specify active/reactive power prioritization.

2.3: This requirement is inconclusive. The requirement must state what TO and GO must do. Otherwise, this requirement is open-ended without a measurable statement. Something regarding "IBR gain" was briefly mentioned during the PRC-029 webinar. A wide spectrum of gains and tuning parameters exist within the IBR controls. The requirement must state what parameters are to be addressed and how to set them. Gains and tuning parameters are covered in MOD-026 and MOD-027 standards and shall not be introduced here. Another potential issue could be with AVR function within the power plant controller. AVR/PPC failure could potentially cause higher voltage outputs. AVR failure, or any equipment failure, should not be the criteria to violate the standard. WEC recommends this requirement be removed.

2.4: WEC owns and operates multiple IBR sites and it is in our experience that the limitation to the 1 second requirement will come from the power plant controller. The ramp rate capabilities of the power plant controllers are far slower than inverter ramp rates and are typically in minutes range. WEC also had an instance where the power plant controller ramp rate increase was denied by the Transmission Operator/Planner.

2.5: This requirement contradicts the meaning of established No-Trip zone. If the No-Trip zone is inadequate, then SDT should evaluate and adjust it accordingly. In addition, having protection settings applied right at the equipment damage curve is not a standard protection practice, especially if events such as voltage excursions have a cumulative effect on insulation degradation that could lead to premature failures. WEC recommends this requirement be removed.

R6.: This requirement should include and cover equipment limitations associated with R3, R4, and R5.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

The NAGF provides the following comments:

a. Requirement R1 - the NAGF request clarification on the term "exchange" being used in the proposed language for Requirement R1.

b. Requirement R2 – the Terms section identified the terms: Continuous Operating Region, Mandatory Operating Region, and Permissive Operating Region but these terms are not specifically referenced in the tables for Attachment 1. The NAGF believes that the regions should be included in Attachment 1 for clarity.

c. The PRC-029-1 draft remains silent on the network condition, so it is unclear how to model the transmission system to test compliance with these requirements. One option is to assume that the transmission grid at the point of interconnection may be modeled as an ideal voltage source. Another option is to model the transmission grid as a voltage with a Thevenin impedance based on a short circuit ratio (minimum and maximum), which would consider the network condition at the point of interconnection. The NAGF requests clarity on this topic regarding testing compliance.

d. The requirement stated in R2.4 for IBRs to restore active power to the pre-disturbance or available level within 1.0 second when voltage at high-side of the main power transformer returns to Continuous Operation Region. Based on the TO studies or requirements, it is recommended that flexibility be allowed in the recovery time requirement. For example, if studies indicate that a slower ramp-rate and/or pause in the power ramp-up is beneficial then that should be allowed. The NAGF also recommends an active power recovery threshold of 90% of pre-disturbance level to account for measurement and IBR unit control uncertainties and tolerances.

e. The requirement stated in R2.1.1 must allow IBRs apparent power to be limited if the voltage is outside the normal operating range and the IBR units have reached their maximum current limit.

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	No
Document Name	

Comment

AZPS supports the following comments that were submitted by EEI on behalf of its members:

EEI agrees with most of the proposed language in Requirements R1, R2 and R6; however, the phrase “of an applicable IBR” should be removed. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant.

EEI also does not support Requirement R2, subpart 2.5 because it contains unneeded language, which adds confusion and implies that GOs can only trip outside of the trip zone if their equipment might become damaged. This has never been an obligation for synchronous generators, and we do not agree that this should be an obligation for IBRs. If NERC or the SDT believe that the no-trip zone needs to be expanded, they should justify such a change and present it for industry review and comment, otherwise, Requirement R2, subpart 2.5 should be deleted.

And while we support Requirement R6 and the provisions to notify PCs, TPs and RC about equipment limitations that would prevent an applicable IBR from meeting ride-through requirements as detailed in Requirements R1 and R2, the Requirement does not go far enough because there may be technical reasons why an applicable IBR is unable to meet Requirement R3 through R5, as well. To address this concern, R6 should be expanded to include Requirement R1 through R5.

Likes 0	
Dislikes 0	

Response

Joy Brake - Nova Scotia Power Inc. - NA - Not Applicable - NPCC

Answer	No
Document Name	

Comment

Concerns are covered other commenters.

Likes 0	

Dislikes 0	
Response	
Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	No
Document Name	
Comment	
PNM agrees with the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	

R2.1/2.2

This states that the TO is who decides whether Active or Reactive Power is prioritized when a limit is reached. IBR sites will curtail real power to meet the reactive power request from the controllers.

R2.4

This section would depend on the ramp rate of the units, 1.0 seconds seems extreme

M2

Will the PC's be communicating in writing to the Generator Owner every time there is a disturbance with the request for this data. How long will the data need to be held?

R4

5 hz/second is not a reasonable rate

M4

Will the PC's be communicating in writing to the Generator Owner every time there is a disturbance with the request for this data. The retention period for data is not defined.

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and North American Generator Forum (NAGF) on question 2

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy supports EEI comments. In addition, Dominion Enetgy has the following comments:

R2, Section 2.1 refers to the Continuous Opera**tion** Region as specified in Attachment 1; however the definition of Continuous Opera**ting** Region at the beginning of the standard is only applicable to voltages, measured at the high-side of the MPT that are between 0.9 PU and 1.1 PU. Does this mean that the definition of Continuous Operation Region is different from Continuous Operating Region? Or is the intent the same as the definition at the front of the standard and the “tion” should be changed to “ting”? Please clarify. This disconnect also exists in R2 and in R2.2.

R2, Section 2.1.2 and R2.4 both allude to a requirement for either the Transmission Planner, Planning Coordinator, Reliability Coordinator or Transmission Operator to provide a preference of active or reactive power if an IBR cannot deliver both due to a current or apparent power limit. The standard is not applicable to any of these listed entities and thus puts an administrative burden on the Generator Owner to contact each to determine a preference. Four entities determining the preference is three too many. A new requirement should be written directing one of the four entities to be the lead point of contact for the GO. Additionally, the standard should specify that the lead entity charged with determining the preference of active of reactive power should communicate the preference a minimum of 6 months prior to the effective date for the GO. The GO cannot put controls in place and ensure compliance until the TP, PC, RC or TOP has documented the compliance requirement.

R6, Section 6.2 is confusing since the Technical Rationale and FERC Order 901 Directives, Paragraph 193 states that “when the existing equipment is replaced, the exemption would no longer apply, and the new equipment must comply with the appropriate IBR performance requirements”. Further, FAC-002-5 considers replacement of inverters / converters or Power Plant Controllers to be “qualified changes” and would require a study before implementation. This section seems to be an unnecessary administrative step, since the FAC-002 process would require submittal of “as-built settings” for the qualified change study.

Likes 0	
Dislikes 0	

Response

George E Brown - Pattern Operators LP - 5

Answer	No
Document Name	

Comment

Pattern Energy supports GRE’s comments for this question.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

Constellation does not agree and feels the HVRT times are very high. Many wind turbines/inverters won't be able to meet those times, equipment in general and these systems have not been designed to withstand that much overvoltage.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	

1 The language “continues to exchange current” in R1 is not clear, please explain.

2 OEMs have not been forthcoming with operating limit data/equipment trip capabilities. Due to the lack of information from OEMs, we are concerned that the following language in R2.5 will be difficult to comply with: “Each IBR shall only trip *to prevent equipment damage*, when the voltage at the high-side of the main power transformer is outside of the no-trip zone as specified in Attachment 1”.

3 The SDT should consider equipment where the manufacturer is not able to provide the limits where equipment damage can occur. For legacy equipment, this information may not be available or may be available at a very high cost to the GO. These scenarios should be included as limitations.

4· Charts in Attachment 1 should be updated to graphically show the performance regions

Likes 0	
Dislikes 0	
Response	

Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	

No, Invenergy disagrees that the language within PRC-029-1 requirements R1, R2, and R6 is clear. Specifically, we offer the below comments regarding these requirements:

R2.1.1.: As currently drafted, R2.1.1. seems to ignore the changes to apparent power limits that could occur during a System disturbance. We recommended the following language:

“R2.1.1. Continue to deliver the pre-disturbance level of active power or available active power, whichever is less, and continue to deliver active power and reactive power up to *the total aggregated current rating of the IBR Units in the plant*.”

R2.1.2.: Invenergy is concerned that the language in R2.1.2. regarding the active power or reactive power preferences of TPs, PCs, RCs, or TOPs may lead to increased confusion and unintended consequences. In its place, we recommend adopting something similar to the p/q/v capability curve demonstrated in Figure 8 of IEEE 2800-2022.

R2.3.: It is unclear to us what R2.3. is requiring. Please clarify or remove.

R2.4.: The ramp rate should be based on System needs; in weaker grid conditions such rapid ramping of active power could lead to power-oscillations or small-signal instability.

R2.5.: This requirement is not auditable and is beyond the scope of the standard, which is to establish certain minimum ride-through requirements. As written, R2.5. suggests GOs should push their equipment as near to its breaking point as possible, even after the minimum ride-through requirements have been met. Thus, we ask R2.5. and similar statements throughout the draft standard be removed.

R6.: Given the technical limitations of many legacy IBRs, R6 must be thoroughly amended to allow exemptions for limitations related to frequency, rate-of-change-of-frequency, and phase angle change ride-through requirements. Consider that there are a range of possible concerns with legacy equipment and equipment already in commercial operation. At one end of the spectrum there exists legacy equipment where the manufacturer is no longer in business, or no longer produces the given IBR unit technology. In these cases, it is often infeasible to either truly document all aspects of the equipment limitations or to attempt to make any software or hardware modifications. At the other end of the spectrum there exists equipment that has been installed in recent years where software modifications may be enough to bring the units into compliance with the proposed requirements, after proper due-diligence and analyses have been performed. In between these two ends of the spectrum there is a range of possibilities.

Where available, software-only modifications are the most likely to yield meaningful reliability improvements where they are most needed while being technically and financially feasible for legacy IBRs to deploy. Indeed, the vast majority of performance issues identified with solar PV resources involved in the 2021 and 2022 Odessa disturbances (and other solar PV resources with the same inverter make/model that were not involved in the Odessa events) are being addressed in ERCOT with software-based modifications (see https://www.ercot.com/files/docs/2024/03/06/Odessa%20Update_03082024.pptx).

Thus, R6 needs a thorough rewrite to give due consideration, and acknowledgement, to these various nuances. Invenergy proposes the below modifications:

R6. Each Generator Owner and Transmission Owner with an applicable IBR that is in commercial operation prior to the effective date of this standard that is unable to meet the ride-through performance requirements detailed in Requirements R1 through R5 shall document the limitation, communicate each equipment limitation to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s), and provide a plan for making reasonable software and settings modifications that reduce or remove the limitation, if available and feasible.

6.1. Each Generator Owner and Transmission Owner shall include in its documentation, in each case as is available or can be reasonably obtained:

6.1.1. Identifying information of the IBR (name, facility #, other)

6.1.2. Current ride-through capability

6.1.3. Known ride-through limitations and documentation of such limitations

6.1.4. Reasonable software and settings modifications

6.1.5. Expected post-modification ride-through capability and documentation of any expected remaining limitations following implementation of such modifications

6.1.6. A schedule for implementing the modifications

6.2. Each Generator Owner and Transmission Owner with a previously communicated equipment limitation that makes a modification that reduces or removes such limitation shall document and communicate such modification to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s) within 30 days of the modification.

To supplement the language regarding reasonable software and settings modifications, the following language could be added to the Technical Rationale: Reasonable software and settings modifications are any available technically feasible modifications involving only software, firmware, settings, or parameterization changes that do not require physical modification of the IBR equipment and are reasonably priced.

Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	

Ameren agrees with EEI's comments.

Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	

No, Invenergy disagrees that the language within PRC-029-1 requirements R1, R2, and R6 is clear. Specifically, we offer the below comments regarding these requirements:

R2.1.1.: As currently drafted, R2.1.1. seems to ignore the changes to apparent power limits that could occur during a System disturbance. We recommended the following language:

"R2.1.1. Continue to deliver the pre-disturbance level of active power or available active power, whichever is less, and continue to deliver active power and reactive power up to *the total aggregated current rating of the IBR Units in the plant*."

R2.1.2.: Invenergy is concerned that the language in R2.1.2. regarding the active power or reactive power preferences of TPs, PCs, RCs, or TOPs may lead to increased confusion and unintended consequences. In its place, we recommend adopting something similar to the p/q/v capability curve demonstrated in Figure 8 of IEEE 2800-2022.

R2.3.: It is unclear to us what R2.3. is requiring. Please clarify or remove.

R2.4.: The ramp rate should be based on System needs; in weaker grid conditions such rapid ramping of active power could lead to power-oscillations or small-signal instability.

R2.5.: This requirement is not auditable and is beyond the scope of the standard, which is to establish certain minimum ride-through requirements. As written, R2.5. suggests GOs should push their equipment as near to its breaking point as possible, even after the minimum ride-through requirements have been met. Thus, we ask R2.5. and similar statements throughout the draft standard be removed.

R6.: Given the technical limitations of many legacy IBRs, R6 must be thoroughly amended to allow exemptions for limitations related to frequency, rate-of-change-of-frequency, and phase angle change ride-through requirements. Consider that there are a range of possible concerns with legacy equipment and equipment already in commercial operation. At one end of the spectrum there exists legacy equipment where the manufacturer is no longer in business, or no longer produces the given IBR unit technology. In these cases, it is often infeasible to either truly document all aspects of the equipment limitations or to attempt to make any software or hardware modifications. At the other end of the spectrum there exists equipment that has been installed in recent years where software modifications may be enough to bring the units into compliance with the proposed requirements, after proper due-diligence and analyses have been performed. In between these two ends of the spectrum there is a range of possibilities.

Where available, software-only modifications are the most likely to yield meaningful reliability improvements where they are most needed while being technically and financially feasible for legacy IBRs to deploy. Indeed, the vast majority of performance issues identified with solar PV resources involved in the 2021 and 2022 Odessa disturbances (and other solar PV resources with the same inverter make/model that were not involved in the Odessa events) are being addressed in ERCOT with software-based modifications (see https://www.ercot.com/files/docs/2024/03/06/Odessa%20Update_03082024.pptx).

Thus, R6 needs a thorough rewrite to give due consideration, and acknowledgement, to these various nuances. Invenergy proposes the below modifications:

R6. Each Generator Owner and Transmission Owner with an applicable IBR that is in commercial operation prior to the effective date of this standard that is unable to meet the ride-through performance requirements detailed in Requirements R1 through R5 shall document the limitation, communicate each equipment limitation to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s), and provide a plan for making reasonable software and settings modifications that reduce or remove the limitation, if available and feasible.

6.1. Each Generator Owner and Transmission Owner shall include in its documentation, in each case as is available or can be reasonably obtained:

6.1.1. Identifying information of the IBR (name, facility #, other)

6.1.2. Current ride-through capability

6.1.3. Known ride-through limitations and documentation of such limitations

6.1.4. Reasonable software and settings modifications

6.1.5. Expected post-modification ride-through capability and documentation of any expected remaining limitations following implementation of such modifications

6.1.6. A schedule for implementing the modifications

6.2. Each Generator Owner and Transmission Owner with a previously communicated equipment limitation that makes a modification that reduces or removes such limitation shall document and communicate such modification to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s) within 30 days of the modification.

To supplement the language regarding reasonable software and settings modifications, the following language could be added to the Technical Rationale: Reasonable software and settings modifications are any available technically feasible modifications involving only software, firmware, settings, or parameterization changes that do not require physical modification of the IBR equipment and are reasonably priced.

Likes 0	
Dislikes 0	

Response

Brittany Millard - Lincoln Electric System - 5

Answer	No
Document Name	

Comment

A review of the data in Attachment 1 and Tables 1 and 2 should be performed so that they align. Currently, the graphs in Figures 1 and 2 do not match what is indicated in the Tables.

We would recommend a part be added to the standard to directly address the Permissive Operating Region, similar to what is done in Part 2.1 (for Continuous Operation Region) and Part 2.2 (for Mandatory Operation Region) as, if left unaddressed, is unclear. For example, there should be some linkage between the body of the standard and Attachment 1, item 10. The following language is provided for consideration (*new* Part 2.3):

2.3 While voltage at the high-side of the main power transformer is within the Permissive Operation Region as specified in Attachment 1, an IBR may operate in current block mode only if necessary to protect the equipment. Otherwise, each IBR shall follow the requirements for the Mandatory Operation Region in Requirement R2.2.

Likes 0	
Dislikes 0	

Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	

Plese review and align the data in Attachement 1 so that data in Tables 1 & 2 align with Figures 1 & 2.

Also, it is recommended a part be added to the standard to directly address the Permissive Operating Region, similar to what is done in Part 2.1 (for Continuous Operation Region) and Part 2.2 (for Mandatory Operation Region) as, if left unaddressed, is unclear. For example, there should be some linkage between the body of the standard and Attachment 1, item 10. See the following proposed language for consideration (*new* Part 2.3):

2.3 While voltage at the high-side of the main power transformer is within the Permissive Operation Region as specified in Attachment 1, an IBR may operate in current block mode only if necessary to protect the equipment. Otherwise, each IBR shall follow the requirements for the Mandatory Operation Region in Requirement R2.2.

OPTION A.

Requirement R6 provides an overly broad exemption as written as the standard is silent as to what criteria must be met. Only notification to other reliability entities is required with no requirement to develop and implement a Corrective Action Plan. The SDT should consider:

- Develop more specific criteria as to what qualifies as an equipment limitation[1], OR
- Require exemptions be submitted to NERC and/or the Regional Entities for approval in order to qualify for the exemption.

OPTION B.

Leave R6 as written, apply R6 to R1 through R5.

it is recommended that there be no requirement to document limitations on legacy equipment and that this standard focuses on equipment brought into service after the implementation date.

R2: We agree with the present flexibility that some of the IBR VRT performance could be modified to meet the individual system needs by the applicable Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator. However, some clarity may be required on how this process is initiated and what type is evidence is required to demonstrate request is received and implemented. This may be an additional requirement assigned to the Transmission Planner. Each Transmission Planner, Planning Coordinator, and Transmission Operator that jointly specifies the following voltage ride-through performance requirements within their area(s) different than those specified under R2, shall make those requirements available to each associated applicable IBR Generator Owner and Transmission Owner

[1] *See Implementation Plan (page 4), i.e. “only those IBR that are unable to meet voltage ride-through requirements due to their inability to modify their coordinated protection and control settings may be considered for potential exemption.” See Technical Rationale (page 9); i.e. specify which voltage band(s) and associated duration(s) cannot be satisfied or specific as to the number of cumulative voltage deviations within*

a ten-second time period that the equipment can ride-through if less than four… identify the specific equipment and explain the characteristic(s) of that equipment that prevent ride-through.

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

We believe that language needs to be added to M1, similar to that provided in the other Measures, to specify the initiating event that triggers the requirement for R1 evidence of compliance.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	No
Document Name	

Comment

Black Hills Corporation supports EEI's and NAGF's comments. Additionally, Black Hills Corporation has concerns regarding event-based "Measures" for Requirement R2, R3, R4 and R5 as GO will likely not have immediate knowledge of "System disturbance" or other transmission system events (transient overvoltage due to switching, frequency excursion, instantaneous positive sequence voltage phase angle changes) when they occur and data collection systems have a limited amount of storage capacity (i.e. data overwrite happens over time, in our case, data is retained for a rolling 12 months). If available data remains the "Measure" for demonstrating compliance, then consideration needs to be given to when and how GO are notified of an event, so data can be reviewed and archived for future demonstration of compliance.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	
Comment	
FirstEnergy finds 2.4 requesting the return to of the Active Power is restrictive and needs to be inclusive of Reactive Power due to voltage response.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
AECI supports comments provided by the NAGF	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	No
Document Name	
Comment	

- 2.1.2 refers to requirements specified by the TP, TOP, PC, RC. It is unclear what the expectation is if those requirements have not been defined.
- Is 2.2.2 is stating that the IBR shall maintain reactive power per default setpoints unless a new reactive setpoint has been requested or it's been requested to maintain a certain active power? Why wouldn't this be worded similarly to the sub-bullets in 2.1?
- 2.3: if the IBR is already responding to Mandatory or Permissive Operation regions (exceedances of Attachment 1 Table 1 or Table 2), how could it then cause an exceedance?

- R2.4 There is concern that the controls will be either unable to respond within the 1 second timeframe, or that the historical records to prove the response would not have the resolution to be meaningful.
- R 2.5: How would someone prove that an IBR tripped only to prevent equipment damage? This sub-bullet cannot be enforced.

Likes 0	
Dislikes 0	

Response

Helen Lainis - Independent Electricity System Operator - 2

Answer	No
Document Name	Proposed change to table Q2.PNG

Comment

The IESO recommends the following modifications to the text improve clarity or to better convey intent.

With regards to R1:

"…as specified in Attachment 1 unless **not doing so is** needed to clear a fault or a documented **and communicated** equipment limitation exists in accordance with **Requirement R6."**

With regards to M1:

"…demonstrating adherence to ride-through requirements, as specified in Requirement R1**, or shall have evidence of a documented and communicated equipment limitation, as specified in Requirement R6**."

With regards to R2:

"…each IBR's voltage performance adheres to the following, unless a documented **and communicated** equipment limitation exists…"

With regards to 2.1: (and Tables 1 & 2, Figures 1 & 2):

There appears to be inconsistency between the definition of 'Continuous Operation Region', the Minimum Ride-Through Time values stated in Tables 1 & 2, and the plots in Figures 1 & 2.

It seems the intent is to have 'continuous' operation between 95% and 105% voltage, and a minimum ride-through time of at least 1800 seconds (half an hour) when voltage is above 105% and not exceeding 110%. If it is really required that equipment must be able to operate ***continuously*** at voltages up to 110%, then the tables and plots should be labelled with a descriptor that implies indefinite operation is required (i.e., continuous) rather than a minimum time (1800 seconds). For example, a version of Table 2 that achieves what seems to be intent could look like the following:

See file attached - Proposed change to table Q2

With regards to 2.5:

The IESO believes the principle of tripping only when necessary (i.e., to clear faults and to prevent equipment damage during disturbances) is important enough that it warrants a dedicated requirement. With regards to tripping during over-voltages, this principle of only tripping for equipment protection purposes may apply equally to system disturbances discussed in R2 and to switching transients as discussed in R3 (tripping for equipment protection is not presently addressed in R3, though is acknowledged in the Technical Rationale document).

With regards to R6:

The IESO suggests there should be explicit requirements to both 'document equipment limitations' and to 'communicate' those documented limitations to the appropriate parties. The following modifications are proposed:

"Each Generator Owner and Transmission Owner with a **known** equipment limitation that would prevent an applicable IBR that is in-service by the effective date of this standard from meeting voltage ride-through requirements as detailed in Requirements R1 and R2 shall **document** each equipment limitation **and communicate it** to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s).

With regards to M6:

Each Generator Owner and Transmission Owner shall have evidence of **known** equipment

limitations, as specified in Requirement R6, **having been** documented **and communicated** to each associated Planning Coordinator, Transmission Planner, and Reliability Coordinator prior to the effective date of PRC-029-1.

Each Generator Owner and Transmission Owner with changes to equipment shall have evidence of communication to each associated Planning Coordinator, Transmission Planner, and Reliability Coordinator.

Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power does not agree that the language in the applicability section of PRC-029-1 is clear. The applicable facilities language in Section 4 is vague and difficult for entities to understand what is in scope of the Standard. Specifically, the term "BPS IBR" is broad and would encompass all transmission connected IBRs, regardless of size or interconnection voltage. Additionally, the language and formatting of the applicability sections in PRC-028, PRC-029 and PRC-030 are not consistent. These three Standards apply to the same facilities, and therefore, should use the same language. Tacoma Power recommends that Section 4 of PRC-029 and PRC-030 should be revised to align with the language proposed in Section 4 of PRC-028, as follows:

4.1. Functional Entities:

4.1.1. Transmission Owner that owns equipment as identified in section 4.2

4.1.2. Generator Owner that owns equipment as identified in section 4.2

4.2. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Likes 1	JEA, 1, McClung Joseph
Dislikes 0	

Response

Leah Gully - Madison Fields Solar Project, LLC - 5 - RF

Answer	No
Document Name	

Comment

See "additional comments" for details

Likes 0	
Dislikes 0	

Response

Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	2020-02_EPRI Comments on Draft NERC PRC-029 (IBR ride-through) Reliability Standard.pdf

Comment

Likes 0	
Dislikes 0	

Response

Michael Goggin - Grid Strategies LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Campbell - David Campbell On Behalf of: Natalie Johnson, Enel Green Power, 5; - David Campbell	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carey Salisbury - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting	
Answer	Yes
Document Name	
Comment	

Yes. The SDT should consider citing IEEE 2800-2022 directly in the standard and consider using the IEEE 2800-2022 ride-through requirements as a means to comply with Requirements R1-R5 instead of using Attachment 1 of the standard.

Likes 0	
Dislikes 0	

Response

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	Yes
Document Name	

Comment

Remove from R1 "*and operation regions*" since this is already required in R2.

Move R2.5 to a sub-requirement of R1, since R1 is the no-trip requirement not R2.

R2.5 should read be rearranged to be more clear, "When the voltage at the high-side of the main power transformer is outside of the no-trip zone as specified in Attachment 1, each IBR shall only trip to prevent equipment damage."

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	Yes
Document Name	

Comment

SRP believes the language in R1 and R2 provides clear expectations of how IBR controls should behave during short circuit events.

Likes 0	
Dislikes 0	

Response

Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
While the language is clear, the SDT explains in the draft PRC-029-1 Technical Rationale that “An IBR becomes noncompliant with PRC-029 only when an event in the field occurs that shows that one or more requirements were not satisfied.” See Question 4 comment for RF’s concerns with this approach.	
Likes 0	
Dislikes 0	
Response	
Stefanie Burke - Portland General Electric Co. - 6	
Answer	Yes
Document Name	
Comment	
PGE supports EEI’s comments	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Since the evidence needed is the actual recorded data, we only need it when there’s an actual event that happened in the system. What if after the event, we found out that we are not compliant? What can we do to ensure compliance? Please add more clarification about the evidence requirements.	
Likes 0	
Dislikes 0	

Response	
Wesley Yeomans - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katrina Lyons - Georgia System Operations Corporation - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
Not Applicable to Reclamation.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	
BC Hydro appreciates the drafting team's efforts and the opportunity to comment, and offers the following: 1. Requirement R2 Part 2.1.2 appears to set an additional Requirement for TP, PC, RC, or TOP to specify requirements for scenarios where an IBR cannot deliver both active and reactive power when the voltage is within the Continuous Operating Region and below 95%. BC Hydro recommends that if these are intended as mandatory or deemed as a necessary input for the IBR Owner/Operator, then these should be codified as standalone Requirement(s) against the appropriate functional entities (TP, PC, RC, or TOP suggested by the current draft). 2. The VSL Table for Requirement R1 does not reflect the allowance of a documented limitation. As drafted, it implies that a Severe VSL will be assessed in spite of a preexisting and documented equipment limitation. BC Hydro recommends that the wording be revised to clarify the compliance expectations when evaluating IBR performance.	
Likes 0	
Dislikes 0	
Response	

3. Do you agree with the drafting team's proposals for including IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in PRC-029-1 Requirements R3, R4, and R5?

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

Designing an IBR plant for transient over-voltage ride-through compliance is complicated by separation of the IBR Units from MPT high side by the non-aggregated collector system including the MPT itself, frequency dependence of the collector system, GSU (i.e., pad mount transformers) and MPT transformer saturation, and surge arrestors on the collector system. DFRs triggered on TOV are essential for monitoring compliance.

Assessing IBR plant phase jump ride-through is dependent on being able to trigger DFR records on non-fault line switching events. Also, as the standard is now written, phase angle jump of any magnitude during a fault must be ridden through and it does not seem possible to determine if a ride-through failure is caused by a fault-caused phase jump exceeding 25 degrees (in which case the IBR could be compliant), or if instead there is a true non-conformity with R1. AEP is not aware if anything can be done about this, but it may be a minor point in most practical situations.

Regarding R4, the technical rationale supporting the standard seems to neglect the possibility of torsional interaction between the wind facilities where sub-synchronous control interaction could exist that can result in possible damage to the wind turbine generator shaft. Therefore, a blanket statement that an inverter-based resource is not affected by off-nominal frequencies may be an assumption that should warrant further considerations when establishing inverter-based resource, frequency ride through requirements. We believe this is supported by page 6 of the technical rationale which states *"In the case of the non-hydraulic turbine synchronous resources, the turbine is usually considered to be more restrictive than generator in limiting IBR frequency ride-through because of possible mechanical resonances in the many stages of turbine blades. Off-nominal frequencies may bring blade vibrational frequencies closer to a mechanical resonate frequency and cause damage due to the vibration stresses. However, inverter- interfaced-IBR does not share this vibrational failure mode."* Furthermore, how should phase jump be considered in R5 where synch check relay settings are greater than 25 degrees?

Likes 0	
Dislikes 0	
Response	

Leah Gully - Madison Fields Solar Project, LLC - 5 - RF	
Answer	No
Document Name	

Comment	
See "additional comments" for details	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State is concerned with the big jump from 61.8 to 64 under Attachment 3, Table 4. We would like to suggest the ride-through requirement be at 62 or 63.	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	No
Document Name	
Comment	

- R3:
  - Technical Rationale "High Voltage Ride Through and Low Voltage Ride Through" modes were not clearly defined. "Mode" implies a specific, programmed, set of actions within controls which may not be real for solar sites.
  - A GO may not know if a switching event occurs. In that case, how would a GO be expected to determine if the event in question is a switching event or not? While R6 addresses exemptions for R1 and R2 in the case that equipment or the ability to record doesn't exist in an existing site, the same may be of concern for the sub-second requirements listed in R3, 4 and 5. The same exclusions should be for the entire standard, if applicable.
- R4:
  - If the Rate of Change of Frequency is 5 Hz/second, there's concern that the level of calculation needed on parameters that may not have more than a 1/second resolution would net little reaction.
- R5:

- While R6 addresses exemptions for R1 and R2 in the case that equipment or the ability to record doesn't exist in an existing site, the same may be of concern for the sub-second requirements listed in R3, 4 and 5. The same exclusions should be for the entire standard, if applicable.

Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
AECI supports comments provided by the NAGF	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports NAGF's and EEI's comments. Additionally, see "Measures" concern noted above in Q2.	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	

No, Invenergy disagrees with the proposals for including IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in Requirements R3, R4, and R5. We offer the below comments regarding these Requirements:

R3: Can the drafting team provide data that demonstrates observed overvoltages during recent System events were of the TOV magnitudes and durations defined in Attachment 2 Table 3? TOVs of such scale are primarily due to the following three scenarios: 1) a lightning strike on the nearby transmission system, 2) transmission line switching transients, and 3) resonant phenomena like voltage magnification due to shunt capacitor switching on the transmission system. Measures are already in place to mitigate such events, including but not limited to proper insulation coordination and substation design, metal oxide varistors, and proper capacitor bank switching of transmission level shunt capacitors (e.g. synchronous switching or use of pre-insertion resistors to mitigate voltage magnification to the extent possible).

To support our statement above, consider an often-quoted document to support these TOV requirements in the NERC Odessa Disturbance Texas Events: May 9, 2021 and June 26, 2021 Joint NERC and Texas RE Staff Report, Dated September 2021. A detailed read of the section that is entitled Inverter Transient AC Overvoltage Tripping Persists identifies poor coordination of controls and protection as the primary driver of these events, rather than TOV conditions at the point of measurement due to switching transients or any type of resonance. What the report explains is that in some cases the IBR units force maximum reactive power output during a fault to push the network voltages up, then once the fault clears they do not pull back on the reactive power injection quickly enough, which leads to an RMS over-voltage (not switching event TOV) at the terminals of the IBR unit, and thus the IBR units tripped. This is solved by 1) proper controls and protection coordination, 2) proper IBR plant design, and 3) proper evaluation of the LVRT and HVRT ride-through capabilities of the IBR plant during the design phase of the plant.

R3 should be removed, and the focus placed on low voltage ride-through and high voltage ride-through, with an emphasis that both LVRT and HVRT performance should be tested during the design phase of a facility using validated IBR unit models based on type-testing.

R4: In the Technical Rationale, the drafting team explains that due to lower system inertia “a wider frequency ride-through capability for IBR **may** be required to avoid the risk of widespread tripping.” Can the drafting team cite more specific reasoning or data to support the expansion of the frequency ride-through capability requirement to the range of 64Hz to 56Hz, well beyond the IEEE 2800-2022 standard frequency ride-through requirement and the capabilities of many legacy IBRs?

The proposed 6-second frequency ride-through capability requirement for the ranges of 61.8Hz to 64Hz and 57Hz to 56Hz does not align with the requirements on the rest of the BES. For the foreseeable future, synchronous generators will continue to be a significant part of the grid. It is a well-established fact that such large electric machinery, which are directly connected to the grid, cannot be exposed to such large variations in frequency. Therefore, it does not seem reasonable to ask IBRs to go to such extremes.

R5: We fail to see the value of requirement R5 given the other ride-through requirements, and it’s unclear to us how an entity is to determine if the subject switching event is initiated by a fault or not. Additionally, we don’t believe the language in R5.1. regarding equipment tripping to prevent equipment damage is reasonable or auditable. We recommend Requirement R5 is removed.

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5	
Answer	No

Document Name	
Comment	

No, Invenergy disagrees with the proposals for including IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in Requirements R3, R4, and R5. We offer the below comments regarding these Requirements:

R3: Can the drafting team provide data that demonstrates observed overvoltages during recent System events were of the TOV magnitudes and durations defined in Attachment 2 Table 3? TOVs of such scale are primarily due to the following three scenarios: 1) a lightning strike on the nearby transmission system, 2) transmission line switching transients, and 3) resonant phenomena like voltage magnification due to shunt capacitor switching on the transmission system. Measures are already in place to mitigate such events, including but not limited to proper insulation coordination and substation design, metal oxide varistors, and proper capacitor bank switching of transmission level shunt capacitors (e.g. synchronous switching or use of pre-insertion resistors to mitigate voltage magnification to the extent possible).

To support our statement above, consider an often-quoted document to support these TOV requirements in the NERC Odessa Disturbance Texas Events: May 9, 2021 and June 26, 2021 Joint NERC and Texas RE Staff Report, Dated September 2021. A detailed read of the section that is entitled Inverter Transient AC Overvoltage Tripping Persists identifies poor coordination of controls and protection as the primary driver of these events, rather than TOV conditions at the point of measurement due to switching transients or any type of resonance. What the report explains is that in some cases the IBR units force maximum reactive power output during a fault to push the network voltages up, then once the fault clears they do not pull back on the reactive power injection quickly enough, which leads to an RMS over-voltage (not switching event TOV) at the terminals of the IBR unit, and thus the IBR units tripped. This is solved by 1) proper controls and protection coordination, 2) proper IBR plant design, and 3) proper evaluation of the LVRT and HVRT ride-through capabilities of the IBR plant during the design phase of the plant.

R3 should be removed, and the focus placed on low voltage ride-through and high voltage ride-through, with an emphasis that both LVRT and HVRT performance should be tested during the design phase of a facility using validated IBR unit models based on type-testing.

R4: In the Technical Rationale, the drafting team explains that due to lower system inertia “a wider frequency ride-through capability for IBR **may** be required to avoid the risk of widespread tripping.” Can the drafting team cite more specific reasoning or data to support the expansion of the frequency ride-through capability requirement to the range of 64Hz to 56Hz, well beyond the IEEE 2800-2022 standard frequency ride-through requirement and the capabilities of many legacy IBRs?

The proposed 6-second frequency ride-through capability requirement for the ranges of 61.8Hz to 64Hz and 57Hz to 56Hz does not align with the requirements on the rest of the BES. For the foreseeable future, synchronous generators will continue to be a significant part of the grid. It is a well-established fact that such large electric machinery, which are directly connected to the grid, cannot be exposed to such large variations in frequency. Therefore, it does not seem reasonable to ask IBRs to go to such extremes.

R5: We fail to see the value of requirement R5 given the other ride-through requirements, and it’s unclear to us how an entity is to determine if the subject switching event is initiated by a fault or not.

Additionally, we don’t believe the language in R5.1. regarding equipment tripping to prevent equipment damage is reasonable or auditable. We recommend Requirement R5 is removed.

Likes 0	

Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	

Comment

1 AES CE agrees that such performance criteria in R3, R4, and R5 needs to be included, but requests modifications and clarifications as requested below:

2· The language in R3 and R5 relating to “switching events” is difficult to track from the GO perspective. If such an event occurs at the Transmission Operator (TOP), we may not be aware of the need to track and assess our IBR performance as applicable to PRC-029 unless notified by the TOP. If a performance issue with an IBR is identified we would need to be informed by the TOP that a switching event occurred to assess applicability to PRC-029.

3 Please update the technical rationale to clearly state that the 5 Hz/second criteria in R4 aligns with IEEE2800.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6	
Answer	No
Document Name	

Comment

These requirements would be a huge expense for sites that currently don't have frequency response capabilities and there is a strong possibility that many would not be capable of meeting based on manufactures. It will not be financially feasible for all project owners to support this change.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response	
George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Invenergy's comments for this question.	
Likes 0	
Dislikes 0	

Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and North American Generator Forum (NAGF) on question 3	
Likes 0	
Dislikes 0	

Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
R5 , First time seeing this type of protective setting, unsure as to whether or not any documentation exists or protective settings currently exist in our fleet for this.	

M5 ,

Will the PC's be communicating in writing to the Generator Owner every time there is a disturbance with the request for this data. How long will the data need to be held?

The values for ride through are different from PRC-24. All current generation sites have targeted to comply with the curve given in PRC-24. The basis of moving these protective curves are unclear.

Likes 0	
Dislikes 0	

Response

Joy Brake - Nova Scotia Power Inc. - NA - Not Applicable - NPCC

Answer	No
Document Name	

Comment

Yes, they are needed but the understanding of what those criteria should be is not evolved sufficiently at this time. Also, large scale EMT network models are not of sufficient quality to assess the criteria in the design phase.

For example, if RoCoF is for a time period of greater than or equal to 0.1 second, it leaves the choice of sample time to the user. The plant can take the 100ms for calculations and meet the criteria. The System Operator criteria may calculate RoCoF over 500ms (as we do) and would see the plant as not meeting criteria for the same event.

The proposed RoCoF of 5Hz/s is higher than IEEE1547 Category I, II and III. Transmission Wind turbines and their capabilities are often the same as DER plants. A transmission facility just has a lot more of them. That said, we are looking to introduce higher RoCoF for DER as they may be vulnerable as we transition to a very high IBR grid.

RoCoF is not calculated during the fault occurrence and clearance? The standard would only apply for loss of a source of generation without a fault? For loss of our tieline for a fault it would not apply but loss of tieline for neighbouring RAS action it would? It is most needed when there is a fault. For a fault, we are also losing the older wind MW as they go into momentary cessation during the fault making the generation loss greater. For simple loss of supply, a high IBR grid is stronger than for a loss of supply due to fault. We apply RoCoF criteria during a fault. Our current criteria for transmission design is 2.4 Hz/s calculated over 500ms. Our current design criteria for generation facilities ride through is 4Hz/s. But it is under review in EMT studies. We do not use rolling average at this time as it is difficult to accurately calculate in PSSE. We hope to be able to move to rolling average as we increase our use of PSCAD study results for operational studies.

How does it align with the RoCoF criteria for synchronous plants? We are surveying our existing thermal plants and it is still a bit of an unknown in some areas. Our current criteria of 4Hz/s applies to all generating facilities.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

The NAGF provides the following comments:

a. Requirement R3 – the NAGF notes that GOs do not have knowledge of BPS/BES "switching events" and requests that the Drafting Team (DT) consider adding a requirement for the TO/TOP to notify the GOs of such events.

b. Requirement R4:

i. The term "applicable IBR" needs clarification.

ii. Request additional clarification/justification regarding the proposed 5 Hz/second threshold.

iii. The NAGF requests clarity on how to test compliance with the TOV Ride-Through requirement during study or plant IBR design phase.

c. Requirement R5:

i. Same concern as identified for R3

ii. The requirements for phase angle shift of 25 degrees should allow IBR tripping if the post-fault system condition is drastically changed and the device protection is activated.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	

- WEC Energy Group disagrees with R3. FERC Order 901 calls for addressing system disturbances. A switching event does not qualify as a system disturbance. In addition, disturbance events summarized this as an anti-islanding protection issue and therefore it should be stated in R3 to reduce confusion. If the SDT decides to keep R3, then R3 should include following text, "unless a documented equipment limitation exists in accordance with Requirement R6."

- WEC Energy Group agrees with inclusion of R4 with following exception: R4 should include following text, “unless a documented equipment limitation exists in accordance with Requirement R6.”
- WEC Energy Group agrees with inclusion of R5 with following exceptions:
    - R5 should include following text, “unless a documented equipment limitation exists in accordance with Requirement R6.”
    - The industry term is known as PLL Loss of Synchronism and is identified as such in disturbance reports. Therefore, R5 should adopt the same to reduce the confusion.

Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy recommends the implementation of EEI and NAGF comments.

Duke Energy also recommends, if not already considered, to verify with OEMs that the inverters can satisfy Att 2. Figure 3 does not align with IEEE 2800 Figure 14; again, making compliance with both requirements more complicated.

The controls only respond to voltage and therefore will have no context of the initiating event as could be implied by the statements in R3 and R5. Recommend adding an exception to R3 worded in a similar format to the exception stated in 5.1.

Likes 0	
Dislikes 0	
Response	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	

R3-5: R6 should apply to R1-R5 to account for equipment limitations that may also apply to R3-R5. Recommend similar language included in R1 and R2 is added to R3-5:

“…unless a documented equipment limitation exists in accordance with Requirement R6.”

Recommend that there be no requirement to document limitations on legacy equipment and that this standard focuses on equipment brought into service after the implementation date.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
These requirements would be a huge expense for sites that currently don't have frequency response capabilities and there is a strong possibility that many would not be capable of meeting based on manufactures. It will not be financially feasible for all project owners to support this change. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	No
Document Name	
Comment	
No technical expertise to comment.	
Likes 0	
Dislikes 0	
Response	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	No

Document Name	
Comment	

Vistra agrees with AEP.

Likes 0	
Dislikes 0	
Response	

Dave Krueger - SERC Reliability Corporation - 10

Answer	No
Document Name	
Comment	

On behalf of the SERC Generator Working group:

Apply the R1 and R2 phrase "…unless a documented equipment limitation exists in accordance with Requirement R6" to R3, R4, and R5 in addition to what is currently proposed in R1 and R2.

For R3 and R5, the GO will not know an over-voltage or phase jump is the result of a non-fault switching event, so is the GO expected to treat all over voltage and phase jump events as non-fault events.

Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	
Comment	

R5.1:

This requirement is beyond the purpose of the standard, which is to establish Frequency and Voltage Ride-through Requirements for Inverter - Based Generating Resources and should be removed.

Likes 0	
Dislikes 0	

Response	
Carey Salisbury - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	

For R3 and R5, the GO will not know an over-voltage or phase jump is the result of a non-fault switching event, so is the GO expected to treat all over voltage and phase jump events as non-fault events.

Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 5	
Answer	No
Document Name	
Comment	

There are several concerns with the equipment limitation exemption language in the draft of R6, and such exemptions not being allowed for R3 and R5. To justify R6 only allowing an equipment limitation exemption for existing resources to R1 and R2, and not the other requirements of PRC-029, the NERC drafting team's technical rationale document points to FERC Order 901:

The objective of Requirement R5 [sic] is to ensure legacy IBR may need to obtain an exemption to the voltage ride-through requirements if hardware replacements or other costly upgrades would be necessary to comply with Requirements R1 or Requirement R2… FERC Order No. 901 states that this provision would be limited to exempting "certain registered IBRs from voltage ride-through performance requirements." This is the reason that no similar provisions are included for exemptions for frequency, rate-of-change-of-frequency (ROCOF), phase angle change ride-through requirements.

First, the R6 equipment limitation exemption should also apply to R3, which requires ride-through for "a transient overvoltage as a result of a switching event whereby instantaneous voltage at the high-side of the main power transformer exceeds 1.2 per unit." As NERC notes, FERC Order 901 directed NERC that existing resources can have equipment limitation exemptions from voltage ride-through requirements, and remaining online during transient over-voltage is clearly a voltage ride-through requirement. Transient over-voltage can damage equipment, so allowing IBRs to protect against this damage is consistent with FERC's intent in Order 901 to only allow tripping that is necessary to protect equipment. Moreover, in many cases making existing equipment better able to withstand transient overvoltages would require replacing or modifying hardware.

For similar reasons, an equipment limitation exemption for existing resources should also apply to R5, which requires ride-through for voltage phase angle changes of less than 25 degrees. FERC Order 901 directed NERC that existing resources can have equipment limitation exemptions from voltage ride-through requirements, and remaining online during voltage phase angle changes should be interpreted as part of voltage ride-through requirements. Remaining online during phase angle changes of less than 25 degrees could be a problem for existing generators, particularly wind generators as phase angle changes can impose mechanical stresses on the wind turbine's rotating equipment. Not allowing an equipment limitation exemption for existing generators under R5 is particularly problematic as it is not typically feasible to retrofit existing wind turbines to increase their ability to withstand mechanical stresses due to phase angle changes. In such cases, making existing equipment better able to withstand voltage phase angle changes would require replacing or modifying hardware. Phase angle changes can damage equipment, so allowing IBRs to protect against this damage is consistent with FERC's intent in Order 901 to only allow tripping that is necessary to protect equipment.

Moreover, a contextual reading of Order 901 indicates FERC was mostly focused on limiting equipment limitation exemptions to existing generators that would have to physically replace or modify hardware, and not strictly limiting such exemptions to a narrow reading of what constitutes voltage ride-through requirements. Paragraph 193 in its entirety, and particularly the first sentence, explain that FERC's intent was focused on exempting existing resources that would have to physically replace or modify hardware: "we agree that a subset of existing registered IBRs –typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements directed herein." FERC continued by directing that "Any such exemption should be only for voltage ride-through performance for those existing IBRs that are unable to modify their coordinated protection and control settings to meet the requirements without physical modification of the IBRs' equipment."{C}[1] As explained above, equipment limitation exemptions for R3 and R5 are likely necessary to ensure some existing generators do not have to physically replace or modify hardware, and thus such exemptions are consistent with FERC's directive in Order 901.

Finally, R6 equipment limitation exemptions should be allowed for resources with signed interconnection agreements as of the effective date of the Standard, instead of resources that are in-service as of that date. Resource equipment decisions are typically locked down at the time the interconnection agreement is signed, and a change in requirements after that point can require a costly change in equipment or settings that may also trigger a material modification and resulting interconnection restudies. The implementation plan for PRC-029 indicates that the effective date for the Standard will be the first day of the first quarter six months after FERC approval. Many resources take significantly longer than that to move from a signed interconnection agreement to being placed in service, so it makes more sense to allow R6 equipment limitation exemptions for resources that have a signed interconnection agreement as of the effective date of the Standard.

{C}[1]{C} Order 901, https://www.ferc.gov/media/e-1-rm22-12-000, at paragraph 193

Likes 0	
Dislikes 0	
Response	

Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	
Comment	

A premise of R3 is knowing of a transient OV, due to a switching event on the transmission system.   The Generator Owner is not going to have the intelligence to know if a transient OV is due to a switching event. So, is the GO expected to treat all OV events as non-switching events?

1. Requirement R3: The Transient Overvoltage Ride-Through requirement is just not ready to be included in a regulatory standard. The measure for this requirement is based on actual recorded data. The existing facilities may not even have recording equipment in place to measure switching transients. The IEEE P2800.2 WG has also struggled to come up with a Design Evaluation procedure to show that the plant would be able to ride-through the specified TOV ride-through requirements.
2. Requirement R4:
    - The intent of “continue to exchange current” is understood, however, the requirement is vague. During frequency excursion events, it is necessary that IBR adjusts active power output in response to frequency deviation. But these details are not necessary in NERC standards, currently. The IBR that “continues to exchange current” but not based on frequency deviation, would comply with the standard requirements, which is not ideal. The TP/PC is expected to specify IBR performance during abnormal system frequency. Hence, the requirement should read as following: Each GO or TO of an applicable IBR shall ensure each IBR remains electrically connected and continues to exchange current **as specified by TP or PC** during a frequency excursion event……
    - Why is there no exception for Volts/Hz limit? This could be an issue for type III WTG and transformer within the plant. The frequency ride-through requirement in the IEEE Std 2800 recognizes Volts/Hz limitation.
3. Requirement R5:
    - Consider revising to read as follows: Each GO or TO of an applicable IBR facility shall ensure that each IBR remains electrically connected and continues to exchange current during non-fault switching events where the instantaneous change in positive sequence voltage phase angle is less than or equal to 25 electrical degrees at the high-side of the main power transformer.
    - Has the SDT discussed how to measure “instantaneous” phase angle jump based on recorded data?
    - Part 5.1 is not necessary. The IBR may not trip because it measured phase angle jump of greater than 25 electrical degrees but may trip due to affects of such a jump in phase angle. Not sure how to even prove that equipment was at risk or not.
    - For R5, the GO will not know if a phase jump is the result of a non-fault switching event, so is the GO expected to treat all phase jump events as non-fault switching events?
    - In R5, what happens if an IBR trips due to phase angle jump while the frequency and voltage remain in the continue to operate range? IBRs will not know whether the system has experienced a fault or not.
4. Attachment 3:
    - Why does the SDT require more stringent ride-through capability compared to the IEEE Std 2800? If a certain interconnection requires stringent ride-through requirement then it should only be required for that interconnection. There is no need to extend the stringent requirements of one interconnection to all interconnections. Such an approach is implemented in the PRC-024, PRC-006, etc. Additionally, the PRC-006 specifies boundaries between which the frequency needs to remain while simulating and designing UFLS scheme. The IBR frequency ride-through coordinated with boundaries in PRC-006 should be enough.
    - Table 4:
        - Not sure what is implied by “average system frequency”. The term “average” makes sense when associated with ROCOF but not with frequency.
        - ≥64 should be >64
        - ≥61.8 should be >61.8
    - Note 1 is not necessary. Which measurement is taken on each phase?
    - Note 2: Consider replacing with following: Frequency is measured over a period of time, typically 3-6 cycles.

- Note 3: not sure which “control settings” are referred here. Consider the following from PRC-024: Instantaneous trip settings based on instantaneously calculated frequency measurement is not permissible.
- Note 5: Why did the SDT specify 15-min time period instead of 10-min time period in the IEEE Std 2800.

ROCOF and phase angle jumps:

- Some legacy IBRs have technical limitations that will prevent them from riding through ROCOF less than or equal to 5 hz / second or phase angle jumps less than 25 electrical degrees. Such IBRs need the ability to seek an exemption for these requirements.Note: ERCOT has questioned the validity of how ROCOF and phase angle jumps are measured, and whether the 5 hz / second and 25 electric degree values are accurate.
- R5 specifies that IBRs must ride through phase angle jumps initiated by **non-fault** switching events and are changes of less than 25 electrical degrees. There is an issue Southern Company has encountered on NOGRR245. ERCOT has proposed that IBRs not trip for any ROCOF or phase angle jumps during **fault** conditions. It is an understanding that IBRs should ignore ROCOF and phase angle jump values during fault conditions. Southern Company would support similar fault language in PRC-029-1, but a technical exemption would be required because some legacy IBRs are unable to distinguish between a fault and non-fault condition.

R6.1.2 discusses *“aspects of VRT requirements that the IBR would be unable to meet”.* This language could be clearer by requesting the IBR to identify actual VRT capabilities.[A1]

M6 requires evidence of equipment limitations prior to the effective date of the standard. This could be extremely challenging to meet.

Finally, Southern Company supports NAGF comments.

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	

Comment

Rwquirement 3

PG&E believes specific requirements for the inverter capabilities should be removed from the NERC standard and left to the IEEE 2800-22 standard for inverter specifications. The utility relies on RMS measurements and does not have a means to accurately measure transient over-voltage conditions for protective relays; therefore, it would be extremely difficult for the entity to prove its compliance.

Requirement 4

Frequency ride-through limits have been raised considering that IBRs can continue to generate. For synchronous machines, it is not possible to have such a wide frequency range (as per attachment 3 copied below). When the system has majority of IBRs, the effect on synchronous machines with such wide frequency variations is unknown. Also, it would affect the underfrequency load shedding schemes.

PG&E has the following questions for the SDT to consider: Should there be separate ride through limits for Grid Forming inverters and Grid Following inverters? Would higher penetration of IBRs affect the allowable frequency ranges?

Requirement 5

PG&E believes specific requirements for the inverter capabilities should be removed from the NERC standard and left to the IEEE 2800-22 standard for inverter specifications.

PG&E has the following question for the SDT: how do we set relays or trigger a DFR for a switching/non-fault event to show compliance with the requirement?

Likes 0	
Dislikes 0	

Response

Mark Flanary - Midwest Reliability Organization - 10

Answer	No
Document Name	

Comment

See comments below under question 4.

Likes 0	
Dislikes 0	

Response

Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	2020-02_EPRI Comments on Draft NERC PRC-029 (IBR ride-through) Reliability Standard.pdf

Comment

Likes 0	
Dislikes 0	

Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
We agree that PRC-024 standard should remain (enforced) because this will also help in ensuring the reliability of the Bulk Power System.	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
The IESO recommends the following modifications to the text improve clarity or to better convey intent. **With regards to R4:** "…continues to exchange current during a frequency excursion event whereby the **system** frequency remains within the "no trip zone" according to…" This suggestion would differentiate the actual system frequency from, say, the frequency measurement as 'seen' by the PLL or other parts of the controls. **With regards to 5.1** As commented above, IESO believes 'not tripping except to provide equipment protection' warrants a dedicated Requirement, which may be referred to the context of other requirements, such as performance during phase angle jumps.	
Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	
Response	
Michael Brytowski - Great River Energy - 3	

Answer	Yes
Document Name	
Comment	

Comments: Initial review indicates the proposed requirements R3, R4 and R5 align with IEEE 2800 which we support.

R3: we suggest adding to attachment 2 how the instantaneous transient overvoltage should be calculated (such as what the pu base? and the minimum sampling rate?)

Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	
Comment	

FirstEnergy has no issue for the direction of these requirements.

Likes 0	
Dislikes 0	
Response	

Stefanie Burke - Portland General Electric Co. - 6

Answer	Yes
Document Name	
Comment	

PGE supports EEI's comments but in addition would add clarification: For the requirement to say "may trip, but shall only trip to prevent equipment damage" does not provide clear direction. If the IBR can stand a 30 electrical degree change, is it acceptable to trip at 25.0 to prevent equipment damage? It would be preferrable to provide a safety margin before reaching the damage point. Or, is this stating that the IBR wait until 30.0 electrical degrees is reached before taking action? What is the measure for making sure an IBR does not trip at 25.0 or above except to protect the equipment? If there is nothing particularly harmful about tripping an IBR above 25.0, why not indicate that above 25.0 is not a "Must Trip Zone/Criteria"?

Likes 0	

Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	Yes
Document Name	

Comment

R3: we suggest adding to attachment 2 how the instantaneous transient overvoltage should be calculated (such as what the pu base? and the minimum sampling rate?)

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 1,3,6

Answer	Yes
Document Name	

Comment

Ameren agrees with EEI's comments.

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	Yes
Document Name	

Comment

AZPS supports the following comments that were submitted by EEI on behalf of its members:

EEI supports the proposal to include IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in PRC-029-1 Requirements R3, R4, and R5. However, the following phrase "of an applicable IBR" should be removed from R3, R4 and R5. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposal to include IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in PRC-029-1 Requirements R3, R4, and R5. However, the following phrase "of an applicable IBR" should be removed from R3, R4 and R5. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Maozhong Gong - GE - GE Wind - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	

Comment	
But we need to consider old units, please see the additional comments below.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
R3: MP agrees with the NSRF's comments on defining the transient overvoltage calculation method. MP also suggests defining the term "current block mode."	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG supports IESO's comments.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	

See EEI Comments

Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	

However, please verify the ROCOF with regards to how FR data at the IBR Unit level (per the definitions proposed by 2020-06) is required to be captured (Per proposed PRC-028-1). Note that PRC-002-4 and -5 have ROCOF triggers for recording that are significantly different than 5 Hz/second. Measure 4 of PRC-029-1 has a reference to a Planning Coordinator's area but Requirement 4 has no such limitation or uses Planning Coordinator within the language. It appears that the stated ROCOF is high based on IRPT reports

(https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf). And the ROCOF definition is different from said report by the IRPTF.

Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	

NextEra aligns with EEI's comments:

EEI supports the proposal to include IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in PRC-029-1 Requirements R3, R4, and R5. However, the following phrase "of an applicable IBR" should be removed from R3, R4 and R5. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant.

Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

ERCOT joins the comments of the IRC SRC and adopts them as its own in addition to the following comments, except to the extent of any specific differences between the SRC comments and the following comments from ERCOT.

Footnote 2 is not clear as to whether RoCoF measurement should begin immediately or upon fault clearing. IEEE 2800.2 discussions are heading in a direction that would indicate that during fault occurrence, clearance, and recovery back to a steady-state operating point, failure to ride through should only be allowed if the voltage is beyond the requirement (i.e., the unit should not trip due to any perceived RoCoF during the entire disturbance and recovery period). This is similar for phase angle jump.

Requirement R4 may need to include language similar to that found in Requirement R5, Part 5.1 to ensure RoCoF is set to the equipment capability and is not arbitrarily set at 5 Hz/s. ERCOT also notes that the IEEE 2800-2 drafting team is identifying that there should be agreement between unit owners and planners/operators on how to measure RoCoF (at what time points, greater than or equal to .1 second) to ensure consistency in testing, model validation, application, and performance evaluation. Otherwise, such a requirement may create confusion or otherwise be unenforceable. IEEE 2800-2 also identifies the potential need for higher RoCoF requirements, which may be appropriate in smaller Interconnections.

The current language in Requirement R5 excludes voltage phase angle change of exactly 25 degrees, which is included in IEEE2800 requirements:

SDT's proposed language:

"Each Generator Owner or Transmission Owner of an applicable IBR shall ensure each IBR remains electrically connected and continues to exchange current during instantaneous positive sequence voltage phase angle changes **that are initiated by non-fault switching events on the transmission system and are changes of less than 25 electrical degrees at the high-side of the main power transformer.**"

ERCOT's proposed language:

Each Generator Owner or Transmission Owner of an applicable IBR shall ensure each IBR remains electrically connected and continues to exchange current during instantaneous positive sequence voltage phase angle **changes of 25 electrical degrees or less at the high-side of the main power transformer that are initiated by non-fault switching events on the transmission system**.

Finally, ERCOT believes that under the Violation Risk Factor guidelines, Requirements R3, R4, and R5 should have a VRF of High as they are requirements "**that, if violated, could directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures** . . . ."

Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI comments	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	

Answer	Yes
Document Name	
Comment	

Overall, we at ACES support Requirements R3 through R5; however, we have a minor concern with the wording of Requirement R3, Option 2. Specifically, we have concerns with the requirement to "restart current exchange within 5 cycles of the instantaneous voltage falling below (and remaining below) 1.2 per unit." For how long of a duration should the instantaneous voltage remain below 1.2 p.u. to trigger the 5 cycles wherein the IBR must resume current exchange? We recommend that the SDT consider adding a time component to the return from the transient overvoltage condition.

Likes 0	
Dislikes 0	
Response	

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2

Answer	Yes
Document Name	
Comment	

Southwest Power Pool joins the ISO/RTO Council Standards Review Committee comments.

Likes 0	
Dislikes 0	
Response	

Darcy O'Connell - California ISO - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee

Answer	Yes
Document Name	
Comment	

Initial review indicates the proposed requirements R3, R4, and R5 align with IEEE 2800, which the SRC supports.

The SRC recommends the following modifications to the text to improve clarity and to better convey the intent of the standard.

Recommended changes to R4:

"…continues to exchange current during a frequency excursion event whereby the **system** frequency remains within the "no trip zone" according to…"

This revision would clarify that the actual system frequency is the relevant measurement instead of the frequency measurement as 'seen' by the PLL or other parts of the IBR control system.

Recommended changes to R5.1

As noted above, the SRC believes 'not tripping except to provide equipment protection' warrants a dedicated Requirement, which may be referred to in the context of other requirements, such as performance during phase angle jumps.

Likes 0	
Dislikes 0	

Response

Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting

Answer	Yes
Document Name	

Comment

Yes. The SDT should consider citing IEEE 2800-2022 directly in the standard and consider using the IEEE 2800-2022 ride-through requirements as a means to comply with Requirements R1-R5 instead of using Attachment 1 of the standard.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Brittany Millard - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
David Campbell - David Campbell On Behalf of: Natalie Johnson, Enel Green Power, 5; - David Campbell	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Shonda McCain - Omaha Public Power District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Katrina Lyons - Georgia System Operations Corporation - 4	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wesley Yeomans - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
Not Applicable to Reclamation.	
Likes 0	
Dislikes 0	
Response	
Imane Mrini - Austin Energy - 6, Group Name Austin Energy	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

4. Provide any additional comments for the Drafting Team to consider, if desired.

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	
Document Name	
Comment	

The proposed PRC-029 seems vague and does not specify what size IBR would applicable. If it is below the 75MVA aggregate, then I believe that would cause undue burden on utilities to meet.

Likes 0	
Dislikes 0	
Response	

Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting	
Answer	
Document Name	
Comment	

Attachment 1 needs a few corrections.

- Figures 1 and 2 use a logarithmic time scale for the Time x-axis. This should be updated to be a regular non-logarithmic time scale.
- There are numerous inconsistencies in this standard language and Attachment 1 when compared to IEEE 2800. These should be considered and reviewed for clarity and completeness in the standard. The option to cite IEEE 2800-2022 and use the requirements in the IEEE 2800-2022 directly should be allowed over just the use of Attachment 1 (give each GO/TO the ability to use either of these guides to base their performance off of).
    - IEEE 2800 identifies the following items, but the standard does not support. Clarification/review should occur for each of these items:
        - Exceptions for Negative-sequence voltage exceeding thresholds
        - IEEE 2800 recognizes Volts/Hz limitations, but the standard does not.
        - IEEE 2800 recognizes 500kV system voltages are actually operated in the range of 525kV and therefore has equipment rated to 550kV. These 500kV operating conditions should be considered in the standard.
        - In IEEE 2800 the frequency ride-through criteria defines 10-minute time periods whereas the standard defines them in a 15 minute time period (Table 4 of Attachment 3). This should be clarified and identified.

The standard is quite vague in terms of technical limitations and documentation exemptions to the requirements. Experience has shown that this is a highly nuanced and difficult consideration. There is no language focused on software versus hardware limitations and what is allowed/expected. This could lead to inconsistent, subjective auditing practices rather than clear objective requirements and auditing.

Likes 0	
Dislikes 0	

Response

Darcy O'Connell - California ISO - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee

Answer	
Document Name	

Comment

The SRC requests several enhancements to **PRC-029**.

1. **Clarify and emphasize that documented equipment limitations under Requirement R6 must not be construed to be complete exemptions from the Requirements of PRC-029.** If entities are unable to ride-through portions of the ride-through curve, this should not automatically exempt them from complying with the balance of the ride-through curve as described in the Technical Rationale. While this is clearly expressed in the Technical Rationale for Requirement R6 (page 9), this point needs to be brought out more clearly in the PRC-029 standard itself.
2. **Expand PRC-029 to require that Corrective Action Plans be developed and implemented to remove equipment limitations within a specified timeline or require a** technical justification that addresses why corrective actions will not be applied nor implemented.
3. PRC-029 will need to explicitly require any new inverter/controller replacing older equipment to be compliant with PRC-029 rather than set to original equipment specification.
4. Applicability:In Introduction, Section 4.2.2, it is not obvious what aspect of 'IBR Registration Criteria' makes an IBR an 'applicable' IBR – is it simply that an IBR meets NERC Registration Criteria? This bullet point should be elaborated upon to ensure clarity.
5. Event-Based Standard: The SRC has concerns that this standard is an event-based standard that does not necessarily provide an assurance of reliability before events occur, such as would be provided by having an engineering analysis or results from bench-testing and real-time simulations of control equipment that indicate that successful ride through of prescribed disturbances is expected.
6. Without disturbance events that show whether IBRs perform properly, there is no way to determine if an IBR is compliant with the standard. At a minimum, the measures (e.g, M2-M5) should be extended to indicate that a statement that no such events are known to have occurred will qualify as evidence of compliance.
7. Presentation of Ride-Through Ranges: The intended ride-through requirements would be made more clear if the 'minimum ride-through times' were associated with precisely stated, *non-overlapping ranges* of voltages or frequencies, such as in the example 'Table 2' provided by the SRC in its comments above.
8. Nominal Voltages: Note #4 of Attachment 1 would be clearer if the 'nominal' system voltage values were listed as they are in Attachment 2 of PRC-024-3, i.e., "(e.g., 100 kV, 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 400 kV, 500 kV, 765 kV, etc.)"
9. Harmonize Tables, Figures, Requirements: The voltage/frequency excursion levels and the associated minimum ride-through times for all tables, figures, and any associated performance requirements that modify the requirements should be carefully reviewed and harmonized. There are presently some conflicting entries in the tables/figures.

10. PRC-029 introduces new terms. The drafting team should consider using these new terms in PRC-024 for consistency. The ranges in these definitions may be specific to IBRs due to their unique performance characteristics, but these regions serve the same purpose for synchronous generators.
    i. Term(s):
    ii. Continuous Operating Region – The range of voltages, measured at the high-side of the main power transformer, that are ≥ 0.9 per unit and ≤ 1.1 per unit.
    iii. Mandatory Operating Region – The range of voltages, measured at the high-side of the main power transformer, that are > 0.1 per unit and < 0.9 per unit – or – > 1.1 and ≤ 1.2 per unit.
    iv. Permissive Operating Region – The range of voltages, measured at the high-side of the main power transformer, that is ≤ 0.1 per unit.
11. There does not seem to be a direct explanation of how these new terms used in the Requirements are applied in Attachment 1, where the ranges for “No-Trip” and “Must-trip” are shown. the only mention of these terms in Attachment 1 appears to be in bullets 8, 9, and 10 where one or two Regions are mentioned and assumed to be understood. Additionally, these terms are not used consistently throughout the standard, as these terms are defined as “Operating Regions,” but frequently appear in the standard as “Operation Regions.” The SRC recommends that the SDT standardize on a consistent format for these terms.

R1. Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that each IBR remains electrically connected and continues to exchange current in accordance with the no-trip zones and operation regions as specified in Attachment 1

Attachment 1

8. The specified duration of the Mandatory Operation Regions and the Permissive Operation Regions in Tables 1 and 2 is cumulative over one or more disturbances within a 10 second time period.

Likes 0	
Dislikes 0	

Response

Mark Flanary - Midwest Reliability Organization - 10

Answer	
Document Name	

Comment

Requirements R1, R2, R3, R4, and R5 and associated Measures do not make it clear whether equipment settings or configurations that render a facility unable to meet the performance requirements constitute a non-compliance prior to the occurrence of an event where the facility fails to meet the performance requirements. An understanding of these requirements as event-based (as described in the current draft of the PRC-029-1 Technical Rationale) would only partially accomplish the risk objectives described in the SAR and in FERC order 901 as many events would not be prevented. This is particularly concerning for frequency excursion events (R4) as these events are relatively infrequent and yet widespread, potentially resulting in the failure of a multitude of IBRs to meet the performance requirements if frequency trip settings are not evaluated preemptively. As such, these requirements should make it clear that facilities are to be configured to meet performance requirements and that the relevant equipment settings should be available as evidence to show compliance.

If there are portions of the performance criteria in this standard that equipment owners cannot be expected to meet through assessment of equipment settings in the absence of an event, those portions should be addressed in separate requirements that specify corrective actions to be performed following an event rather than identify non-compliance at the time of the event.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	

Comment

Attachment 1, Part 2b. I assume that “ESS” means Energy Storage System? Please document or clarify.

Part 7 “ … trip …” again. Same question as in comment 2 above. The second sentence is also unclear. What is “the 10-second time period”? Is this phrase identified in Parts 8 and 9? If so, please define it before first use and use the same phrase subsequently.

Attachment 2 Part 3 “ … trip …” again. Same question as in comment 2 and Attachment 1 Part 2b above.

Attachment 3, Table 4 Part 2. I agree with averaging frequency over a set time period. But 3 cycles seems rather short to assure a reasonable frequency value, especially during fault conditions. IEEE 2800 says “… at least 0.1 sec” [6 cycles] for ROCOF, and that is probably a good target for frequency also.

Table 4 and Part 4 “ … trip …” again. Same question as in comment 2 and Attachment 1 Part 2b and 3 above.

Likes 0	
Dislikes 0	

Response

John Pearson - ISO New England, Inc. - 2

Answer	
Document Name	

Comment

The new or modified terms should define what the “voltage” is, RMS, Positive Sequence? Instantaneous? Etc. for Continuous Operating Region, Mandatory Operating Region and Permissive Operating Region.

In Attachment 1, bullet 3 is problematic, basing the applicable table based on direction by the Transmission Planner needs to have a specific requirement describing how that would be done. Bullet 4 is also problematic for the same reason. Bullet 8 – Mandatory Operation Regions should conform with IEEE 2800 7.2.2.4 for consecutive disturbances, and differentiate from dynamic voltage oscillations. Bullet 9 should also conform to IEEE 2899 7.2.2.4.

Likes 0	
Dislikes 0	

Response

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2

Answer	
Document Name	

Comment

Southwest Power Pool joins the ISO/RTO Council Standards Review Committee comments.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators

Answer	
Document Name	

Comment

- It is the opinion of ACES that Section 4.2 should be modified to utilize the registration criteria as defined in the latest revision of the NERC Rules of Procedure.

Thus, we recommend the following revisions to Section 4.2:

4. Applicability:

4.1 Functional Entities:

4.1.1 Generator Owner that owns an applicable facility in Section 4.2.1.

4.1.2 Transmission Owner that owns an applicable facility in Section 4.2.3.

4.2 Facilities:

4.2.1 Either of the following Inverter-Based Resource (IBR)1 types:

4.2.1.1 BES IBR

4.2.1.2 non-BES IBR that is:

4.2.1.2.1 Connected to the Bulk Power System, and

4.2.1.2.2 Meets the criteria for a Category 2 GO facility.

4.2.2 High-voltage Direct Current (VSC-HVDC) Transmission facilities that serve as a dedicated connection for an Inverter-Based Resource meeting the criteria of 4.2.1.1

- Transmission is a defined term in the NERC Glossary of Terms. As it is currently defined, this term does not specify a voltage threshold for its applicability; therefore, we recommend capitalizing all uses of the word "transmission" within PRC-029-1 for the sake of clarity.

Likes 0	
Dislikes 0	

Response

Katrina Lyons - Georgia System Operations Corporation - 4

Answer	
Document Name	

Comment

GSOC supports Georgia Transmission Corporation (GTC) Comments.

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	
Document Name	

Comment

See comments submitted by Edison Electric Institute

Likes 0	
Dislikes 0	

Response
Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment
See EEI comments

Likes 0	
Dislikes 0	

Response
Kinte Whitehead - Exelon - 3

Answer	
Document Name	

Comment
Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT joins the comments of the IRC SRC and adopts them as its own in addition to the following comments, except to the extent of any specific differences between the SRC comments and the following comments from ERCOT.

The proposed changes to PRC-024 create a reliability gap, as Type 1 and Type 2 wind turbines are not synchronous machines and would therefore no longer be required to comply with PRC-024 but are not included in PRC-029 because they are not IBRs. The SDT should consider including a specific requirement in PRC-024 or PRC-029 that addresses this technology and requires these types of units to try to meet requirements up to their equipment limitations, to notify their PC/TP/RC/TOP of such limitations, and to reflect any such limitations in their dynamic models. This will ensure that the PC/TP/RC/TOP can incorporate the expected performance of these units in their studies.

ERCOT agrees with the SDT's overall approach of ensuring that PRC-029 is clearly a performance-based standard. However, the standard is not entirely clear on this point, as the Time Horizon is "operations assessment" instead of "Real-time Operations." Additionally, the standard generally uses a structure of 'owners…shall… ensure that' instead of an 'owners….shall.. perform' structure. Structures found in other standards, such as BAL-001's 'entity…shall.. operate such that…' structure or BAL-001-TRE's 'entity….shall….meet (or exceed)' structure may also work well for PRC-029.

ERCOT notes that FERC Order 901 states, "we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system disturbances and that permit IBR tripping **only to protect the IBR equipment** in scenarios similar to when synchronous generation resources use tripping as protection from internal faults. The new or modified Reliability Standards must require registered IBRs to continue to inject current and perform frequency support during a Bulk-Power System disturbance" (emphasis added). To meet this directive, it may be important to clearly specify that partial failures (individual IBR unit trips or abnormal responses) also fall under PRC-029.

ERCOT therefore recommends modifying the Purpose statement for PRC-029 as follows: "To ensure that Inverter-Based Resources**, and their IBR Units,** remain connected and perform operationally as expected to support the Bulk-Power System during and after defined frequency and voltage excursions."

The figures in Attachments 1, 2, and 3 appear to be intended to be graphical representations of the tables. To that extent, they are redundant (and potentially contradict what is in the tables). They may be valuable in visualizing the requirements, but they are also ambiguous in that the lines are not precisely defined, and it is not clear if ride-through is required on the lines themselves. ERCOT recommends that these figures be moved to the Technical Rationale or that Attachments 1, 2, and 3 include a clarification that the plots are for visualization purposes only and that the tables define what is actually enforceable

Item 7 in Attachment 1 should not imply that the IBR shall trip beyond the minimum duration. While the inclusion of the term "minimum" helps clarify item 7, the "shall not trip until…" language implies that the IBR shall trip once the minimum ride-through time duration has elapsed.

SDT's proposed language:

"At any given voltage value, each IBR shall not trip until the time duration at that voltage exceeds the specified minimum ride-through time duration. If the voltage is continuously varying over time, it is necessary to add the duration within each band of Tables 1 and 2 over the 10-second time period to determine compliance."

ERCOT's proposed language:

"The IBR shall ride through voltage conditions beyond those specified in Tables 1 and 2 above to the maximum extent the equipment allows. If the voltage is continuously varying over time, it is necessary to add the duration within each band of Tables 1 and 2 over the 10-second time period to determine compliance."

Similar wording should also be applied in item 3 of Attachment 2 and item 4 of Attachment 3.

ERCOT is concerned that item 10 in Attachment 1 ("If the positive sequence voltage at the high-side of the main power transformer enters the Permissive Operation Region, an IBR may operate in current block mode if necessary to protect the equipment") is inconsistent with the following directive from paragraph 190 of FERC Order 901 (as cited in the technical rationale): "Any new or modified Reliability Standard must also require registered IBR generator owners and operators to prohibit momentary cessation in the no-trip zone during disturbances."

The proposed defined terms do not seem to be appropriate for the NERC glossary, especially if they are intended to be used exclusively for IBRs. If the SDT keeps these proposed terms, the definitions should be improved to include durations in addition to voltage ranges and to note that they are only valid for application to IBRs. Furthermore, there are inconstancies between these terms and Tables 1 and 2 in Attachment 1. For example, the Continuous Operating Region is defined as 0.9-1.1 pu (inclusive), but the tables specify only a one second ride-through time for 1.1pu voltage and an 1800 second ride-through time for voltages greater than or equal to 1.05pu, which is not consistent with the concept of continuous operations. Additionally, the terms are used inconsistently in PRC-029, as the terms are defined as "Operating Regions," but frequently appear in PRC-029 as "Operation Regions."

The Technical Rationale includes the following language:

"The proposed PRC-029 must be understood as an event-based standard. Compliance with PRC-029 is determined from IBR ride-through performance during transmission system events in the field and not from interconnection studies, transmission planning studies, operational planning studies, or from IBR models."

ERCOT recommends that the SDT add basic expectations to the Technical Rationale instead of simply stating that compliance is not determined by studies. For example, GOs should design and/or test their facilities to help ensure they won't be non-compliant during an actual event. Furthermore, it would be helpful to offer advice or SDT opinions on how ride-through should be evaluated during design, interconnection, planning, and operational studies. Even though deficient performance in such studies may not be a violation of PRC-029, it makes little sense to proceed with or allow an interconnection of a plant whose simulation models indicate that it will be unable to comply with PRC-029. Such guidance in the Technical Rationale would be beneficial for industry even if the Requirements in the standard do not contain a corresponding mandate.

The Technical Rationale should describe the basis for the "6-second frequency ride-through capability requirement for frequencies in the ranges of 61.8Hz to 64Hz or 57.0Hz to 56.0Hz range," as it is unclear why this approach was chosen instead of an approach that goes all the way up to 65 Hz and down to 55 Hz for 10 seconds or only up to 63.5 Hz and down to 56.5 Hz for 5 seconds.

It is also unclear how the SDT addressed the phase lock loop (PLL) loss of synchronism concerns discussed in FERC Order 901. While there is certainly an interrelationship, certain protection systems like PLL loss of synch may not need to be enabled. Even if enabled, these systems may, if not correctly configured, require additional tuning to ensure the PLL circuit properly controls and prevents some of the other parameters from tripping the unit offline (e.g. phase angle, RoCoF, and overvoltage). The SDT should consider adding additional language to PRC-029 to clarify that phase lock loss of synchronism trips (whether directly or indirectly involved) are not allowed.

The SDT should also consider adding the following items to Attachment 1 for clarity:

11. To the extent possible, IBRs should not use these curves as the absolute voltage or frequency protection set points but should strive to exceed them up to their equipment capabilities while still ensuring adequate equipment protection.

12. IBRs are not required to trip when voltage and frequency are in the may-trip or permissive operation regions.

Additionally, ERCOT has overall concerns with the work plan pushing the planner and operator requirement changes to the final phases. FERC Order 901 states, “To the extent NERC determines that a limited and documented exemption for those registered IBRs currently in operation and unable to meet voltage ride-through requirements is appropriate due to their inability to modify their coordinated protection and control settings, we direct NERC to develop new or modified Reliability Standards to mitigate the reliability impacts to the Bulk-Power System of such an exemption. As NERC will consider the reliability impacts to the Bulk-Power System caused by an such [sic] exemption, we believe that the concerns raised by NYSRC and Indicated Trade Associations on the appropriate registered entity responsible for implementing the mitigation activities, and the nature of such mitigation, should be addressed in the NERC standards development process.”

Due to the interrelationship between these factors, the allowance for limited exemptions should be linked to the need to mitigate the impact of such exemptions, which will take time in and of itself. In addition, Order 901 directs NERC to consider the reliability impacts of such an exemption. If the SDT does not have identified quantities or models of likely exemptions to assess the impact of allowing exemptions, it is unclear how NERC is considering the reliability impacts of allowing exemptions. There must be guardrails in place to ensure that exemptions are truly limited, not open-ended, and there should be verification by means of accurate models and studies that the system can withstand the impacts of exemptions. If such studies demonstrate unreliable operations (i.e. Instability, Cascading Outages, and uncontrolled separation) would result from granting exemptions, then the exemptions should not be accepted. While ERCOT understands the impacts to generator owners, such assessment and determination should be made under FERC’s direction to ensure that the limited exemptions and risk posed by such exemptions are balanced in such a way that the system maintains Reliable Operation.

Finally, regarding the implementation plan, ERCOT does not agree with how the FERC Order 901 excerpt quoted under "Equipment Limitations and Process for Requirement R6" has been applied. The FERC Order 901 excerpt refers to "typically older IBR technology," which would exclude a majority of IBRs that are in operation today. Aligning eligibility for PRC-029-1 exemptions based on documented equipment limitations under Requirement R6 with the effective date of PRC-029-1 would allow potentially hundreds of GWs of newer IBRs to qualify for exemptions. Such an allowance could result in a failure to realize the reliability benefits FERC intended to capture, as it would allow legacy IBRs to claim exemptions even if they are ultimately capable of complying with the requirements of PRC-029. Unless there is assurance, based on validated and accurate models, that planners and operators can verify that the System can withstand the impact of allowing these exemptions, this allowing this level of potential exemptions may not allow for Reliable Operations. In such instances where exemptions may not allow for Reliable Operations, there should be additional evaluation of available physical modifications (e.g. upgrade kits, new power plant controllers, new controller cards/circuits, control communication networks, component upgrades) for IBR technology that is not approaching its end of life and or an upcoming replacement/refurbishment cycle like "typically older IBR technology" is. Additionally, IBRs that make physical modifications to achieve compliance or that have to make software changes at multiple sites may need additional implementation time when such changes require changes at each individual inverter or turbine.

ERCOT expresses appreciation for all of the SDT’s hard work in meeting an expedited timeline for developing a technically complex set of Requirements that attempts to balance elements from IEEE 2800, FERC Orders, NERC recommendations, and vast amounts of stakeholder input. The SDT is to be commended for its progress thus far on this critical standard.

Likes 0	
Dislikes 0	

Response	
Shonda McCain - Omaha Public Power District - 6	
Answer	
Document Name	
Comment	
OPPD supports comments provided by GRE: Michael Brytowski, Great River Energy, 3, 4/17/2024	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	
Document Name	
Comment	
For PRC-029-1 PG&E asks the SDT the following question: Does Table 1 or 2 apply to Type 4 Wind IBRs? It is unclear which table it would apply to and should be clarified since Table 1 specifies “Wind IBR” but not which types of Wind IBRs. PG&E suggests reconsidering the use of the term “trip” or “no-trip.” Per IEEE 2800-22, “trip” for IBRs may not mean the same as has been traditionally used for synchronous machines and other electric elements. For PRC-024-4 PG&E has the following question for the SDT to clarify: For Transmission Owners, does new language in sections 4.1.2 & 4.2.2 only apply to Synchronous Condensers?	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	

Document Name	
Comment	

NextEra aligns with EEI's comments:

PRC-029-1 (Applicability Section) Comments: EEI does not support the Applicability Section of PRC-029-1 for the following reasons:

{C}1. Applicability details should not be contained in footnotes. Please remove footnote 1 from the Applicability Section.

{C}2. Voltage Source Converter – High-voltage Direct Current (VSC-HVDC) are not defined or justified within the Technical Rationale as to why these resources need to be added PRC-029.

{C}3. Without a justification of a need to include VSC-HVDC systems, TOs should be removed from PRC-029-1.

{C}4. EEI does not support the use of the term “BPS IBRs” because no such term exists in the NERC Glossary of Terms that might provide entities with the knowledge to know definitively which IBRs are applicable.

{C}5. EEI also does not support language that points to the registration criteria.

To address our concerns, we suggest the following changes to the Applicability Section of PRC-029-1, noting the Facilities portion of our comments utilize the recommendations from the Project 2020-06 SDT (see boldface changes below):

{C}**4. Applicability:**

{C}4.1 Functional Entities:

{C}4.1.1 Generator Owner

{C}**4.1.2** {C}**Transmission Owner (and footnote 1)**

{C}4.2 Facilities: **(1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. For purposes of this standard, the term “applicable Inverter-Based Resource” or “applicable Inverter-Based Resources” refers to the following:**

{C}**4.2.1** {C}**BPS IBRs**

{C}**4.2.2** {C}**IBR Registration Criteria**

PRC-024 Comments: While there were no questions related to the proposed modifications to PRC-024-4, EEI does not support all of the proposed changes made to PRC-024-4. Note the following:

Applicability Section of PRC-024-4

EEI does not support changing the intent of 4.2.1.4 (Previously 4.2.1.5) to include multiple synchronous generators connecting to a common bus under the BES Definition, Inclusion I4. Since the development of the BES definition, Inclusion I4 did not include or intend to include synchronous generators. Had that been the intent, the SDT could have included synchronous generator resources in I4. Furthermore, the BES Reference Document states in Chapter I4: BES Inclusion the following:

Dispersed power producing resources are small-scale power generation technologies that use a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include, but are not limited to: solar, geothermal, energy storage, flywheels, wind, microturbines, and fuel cells.

While EEI is open to making modifications to the BES Definition, trying to provide interpretations within individual Applicability Sections of proposed NERC Reliability Guidelines is not the proper method to make such a change. For this reason, and since 4.2.1.4 (previously 4.2.1.5) was intended to address IBRs; this part of the Applicability Section of PRC-024-4 should be deleted.

Comments on the proposed New Definitions

EEI has no concerns with the proposed new definitions, but we do have some non-substantive comments on their usage throughout PRC-029, Implementation Plan and Technical Rationale. (See below)

{C}· Usage of the newly defined terms deviated from the defined term within PRC-029 and the Technical Rational. (i.e., Operating vs. Operations)

{C}· Incorrectly stating in the Implementation Plan that there were no newly defined terms. Please correct this error.

Continuous Operating Region – Only used once in Requirement 2.3.

{C}· Continuous Operation Region used in Requirements 2.1, 2.1.2, 2.4, & once in Attachment 1 (i.e., suggest changing the defined term to Continuous **Operation** Region or correct to Continuous **Operating** Region throughout)

{C}· Continuous Operation Region used twice in the Technical Rationale; Continuous Operating Region never used in the Technical Rationale.

Mandatory Operating Region – Never used in PRC-029

{C}· Mandatory Operation Region used in PRC-029 in Requirements 2.2, 2.3, 2.4 & once in Attachment 1 (i.e., suggest changing the defined term to Mandatory **Operation** Region or correct to Mandatory **Operating** Region throughout)

{C}· Mandatory Operation Region was used twice in Technical Rationale; Mandatory Operating Region was never used in the Technical Rational.

Permissive Operating Region – Never used in PRC-029

{C}· Permissive Operation Region used in PRC-029 in Requirements 2.3, 2.4, & used twice in Attachment 1 (i.e., suggest changing the defined term to Permissive **Operation** Region or correct to Permissive **Operating** Region throughout)

{C}· Permissive Operation Region used once in the Technical Rationale; Permissive Operating Region never used in the Technical Rationale.

Likes 0	
Dislikes 0	

Response	
Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	

Has the MPT Volts/Hz capability been considered when considering the high voltage/low frequency curves?

For R6, the use of "repair" seems inappropriate - an equipment limitation is not equivalent to a broken part in need of repair. We suggest that "repair(s) or replace the limiting element" in R6.1.4 and R6.2 be changed to "remedy the equipment limitation".

The standard requires IBR to ride-through regardless of operating condition of the transmission system. The IBR is typically designed to ride-through for planning events, most likely defined in TPL-001 standard. Considering 24 hour/365 day operation, the transmission system may be experiencing outages beyond planning events. During such an abnormal operating condition, the IBR may not be able ride-through system disturbances as specified. The same could also be true as the transmission system changes over time, as new transmission lines are added to the transmission system and generating plants are added to or removed from the transmission system. The IBR which is designed to ride-through certain transmission network and operating conditions at the time of entering commercial operation may not be able to do so if transmission network and operating conditions change significantly over time. The standard needs to recognize such issues and grant an exception if IBR fails to ride-through.

The SDT proposes to add continuous operating region, mandatory operating region, and permissive operating region terms to the Glossary of Terms. However, these terms are specific to voltage ride-through requirements. There is no reason to limit those terms to voltage ride-through capability only. The continuous and mandatory operation region terms could be applied to frequency ride-through capability as well. Refer to IEEE 2800 to see how these terms are used for both voltage and frequency ride-through capabilities.

Continuous/mandatory/permissive operating region terms:

1. The SDT uses continuous/mandatory/permissive “operating” region as well as continuous/mandatory/permissive “operation” region. Be consistent with either “operating” or “operation” throughout the standard.
2. Following comments to align voltage ranges in Attachment 1, Tables 1 & 2:
    - Mandatory Operating Region term should read like following: The range of voltages, measured at the high-side of main power transformer, that are ≥ 0.1 per unit and < 0.9 per unit OR > 1.1 per unit and ≤ 1.2 per unit.
    - Permissive Operating Region term should read like the following: The range of voltages, measured at the high-side of main power transformer, that is ≤< 0.1 per unit.

3. These terms specify voltage threshold, but which voltage is used in these terms is in the Attachment 1. Per attachment 1, the continuous and mandatory operating regions are based on phase-to-ground or phase-to-phase voltages. But the permissive operating region is based on positive-sequence voltage. The defined terms should also make it clear which voltage thresholds are defined.

Consider revising the purpose statement as following: To ensure that Inverter-Based Resources (IBRs) remain connected and support the Bulk Power System (BPS) during and after frequency and voltage excursions events.

Transmission Owner is included as a Functional Entity in section 4. However, footnote 1 makes it confusing. Would standard only apply to Transmission Owner when it owns the VSC-HVDC transmission facility connecting isolated IBR with BPS?

Currently, PRC-029-1 allows for a GO or TO to seek an exemption from meeting voltage-ride through requirements in R1 and R2.

Southern Company believes that GOs and TOs should be able to seek exemptions from meeting frequency and voltage ride-through requirements in R1 – R5.

The proposed standard only provides for VRT exemptions. Any consideration for FRT, ROCOF, phase angle?

Comment to PRC-024-4:

Facilities section 4.2.1.1 should include I2 of the BES definition and section 4.2.1.4 be removed or reference I2 in place of I4. I4 of the BES definition was intended to point to IBRs at the time of the latest BES definition adoption in 2018 as dispersed power resources and was not intended to point to synchronous generation resources.

Opportunity to clarify that legacy IBRs must maximize capabilities:

1. For NOGRR245, it has been advocated that legacy IBRs should make software / settings changes to maximize capabilities to meet or approach the new ride-through requirements, unless such changes are unreasonably priced.
2. Southern's experience is that software / settings changes are commercially reasonable. The "unreasonably priced" language is intended to protect against price gauging from OEMs.
3. The current PRC-029-1 draft requires legacy IBRs to meet the new voltage ride-through requirements unless a documented technical limitation exists. So a legacy IBR can document an exemption and have performance capabilities less than new VRT standard. But what happens if that legacy IBR owner later learns there is an available software / setting change that would reduce or remove the limitation? The current draft need clarity to address this.
4. Southern Company supports such a software / setting deployment requirement and believes it would (1) be commercially reasonable and (2) more clearly require ride-through capability maximization.

Finally, Southern Company supports EEI and NAGF comments.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer	
Document Name	

Comment

While inclusive, is PRC-024-4 Facility Section Part 4.2.1.4 applicable to synchronous generators? Inclusion 4, when written, was designed to catch the wind/solar aspects of the generation fleet. Inclusion 2 seems to be more appropriate (if not already covered in 4.2.1.1). The MPT footnote appears to be limited to Quebec TO synchronous generators and does not include a reference to synchronous condensers (4.2.2

synchronous condenser applicable facilities simply says "step-up transformer(s)"). In PRC-024-4 Requirement 2 there is a reference to "MPT" and the introduction of Transmission Owner within Requirement. It is not clear if applicable to TOs outside of Quebec based on the language provided (from Requirement R2---"…a voltage excursion at the high-side of the GSU or MPT…" which the GSU/MPT is not mentioned in applicable Facilities for synchronous condensers Section 4.2.2). In Attachment 1 there is a similar issue in that footnote 8 on page 21 mentions the high-side of the GSU or MPT—Also should be noted that Footnote 8 does not appear to have an anchor (location within document to reference the footnote). On page 22 of Attachment 2A there are references to the GSU/MPT as well. Just seeking clarification to avoid an entity having a synchronous condenser indicating no applicability because of the language. This inconsistency in language does not appear to follow items 8 ("Clear Language") and 10 ("Consistent Terminology") of the Ten Benchmarks of an Excellent Reliability Standard as referenced in the Guideline for Quality Review of NERC Reliability Standards Project Documents.

PRC-029-1- SDTs need to use the same IBR terms and not add additional descriptors. Even the title of the Standard is not consistent. Should use the proposed definitions in 2020-06 Verifications of Models and Data for Generators for clarity and consistency. There is no such Facility as "IBR Registration Criteria". Footnote 1 contains undefined terms which should be defined within this Standard if used. Because of the inconsistency in definition use, it is not clear whether this applies to the IBR or IBR Unit locations (even when stated that it does not apply to "individual inverter units or measurements takes at individual inverter unit terminals." If looking at Project 2020-06, the inverters in a "common IBR Unit configuration' as shown in Figure 2.2 and 2.3 of the Technical Rational are exactly at the individual IBR Units (see link [2020-06_IBR_Definitions_Technical_Rationale_02222024.pdf (nerc.com)]). Is "exchange current" considered the same as "inject current" which is used (various ways) in other Standards being proposed? The new terms introduced address range of voltages that may not correlate to the Tables effectively. The Continuous Operating Region definition shows to **include** 1.1 per unit and should reflect the 1800 seconds in Table 1 and Table 2 but the 1.1 voltage per unit in the Tables show only a 1 second capability (Mathemataical expression includes 1.1 per unit in the Table which it should not). Furthermore the 1.2 voltage per unit is shown to be included in the Mandatory Operating Region but NOT in the Tables. Please clarify the expectations as entities had an issue in PRC-024 setting protection on the curves when initially mandatory. With conflicting information, and Figures that are not as explicit or appear to match the Tables, WECC is concerned there may be confusion. This language does not appear to follow Item 8 ("Clear Language") and 10 of the Ten Benchmarks of an Excellent Reliability Standard as referenced in the Guideline for Quality Review of NERC Reliability Standards Project Documents.

At a minimum, bullet 2 under Attachment 1 Table 2 should mention all the types of IBR as listed in other Standards (Type 3 and type 4 of wind is covered in bullet 1, "Isolated IBR" is undefined, and 2.b. simply says "Other IBR plants" and limits hybrid to PV and "ESS" (possible typo that should be "BESS"?). The "not limited to" should remain and the SDT may say all are covered with said language but clarity could be provided by adding consistent language as used in other Standards. This inconsistency in language does not appear to follow items 10 ("Consistent Terminology") of the Ten Benchmarks of an Excellent Reliability Standard as referenced in the Guideline for Quality Review of NERC Reliability Standards Project Documents.

Attachment 1 Table 2 Bullet 3 leaves the applicability to the TP but the TP is not called out as an applicable entity and this is an Operations Assessment time horizon. In the Technical Rationale it clearly states "*Compliance with PRC-029 is determined from IBR ride-through performance during transmission system events in the field and not from* ***interconnection studies, transmission planning studies****, operational planning studies, or from IBR models*." So, if IBRs in a hybrid plant have issues, the TP is to blame for calling out the incorrect Table? TPs may very well have the studies to determine how long a ride-through should be sustained by IBRs, but there is no compliance responsibility (not saying there should be—should be responsibility properly assigned through the Standards process). Bullet 4 allows the PC or TP to change the Requirement criteria but there is no accountability if done (furthermore no notifications for awareness to those entities in the Operations side of business). The apparent responsibility does not appear to follow items 1 ("Applicability") of the Ten Benchmarks of an Excellent Reliability Standard as referenced in the Guideline for Quality Review of NERC Reliability Standards Project Documents.

"MPT" is not defined in the Standard yet used repeatedly. Clarity can be provided with a footnote or addition of a definition (not that synchronous condenser use in PRC-024-4 was unclear for MPT).

There are only Severe VSLs for Requirements R1 through R5. Clarity on where the inverter is (based on the 2020-06 drawings provided and language in this Standards Technical Rational) will be important to understand. Failure of individual IBR units (as defined in 2020-06) appears to not be addressed9unless it is intended to be addressed by the Sever VSL) and will have an impact on being complaint at the IBR level.

Likes 0	
Dislikes 0	

Response

Romel Aquino - Edison International - Southern California Edison Company - 3

Answer	
Document Name	

Comment

See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	
Document Name	

Comment

See EEI Comments

Likes 0	
Dislikes 0	

Response

Carey Salisbury - Santee Cooper - 1,3,5,6, Group Name Santee Cooper

Answer	
Document Name	

Comment

For each of the measures M1-M5, what “other evidence” can demonstrate compliance with R1-R5 other than recorded data? How does the drafting team believe that generator owners can assure this performance expectation can be achieved prior to an actual event? There is no test verification that can be performed to confirm the expected performance that considers every type of system disturbance that can occur.

Likes 0	
Dislikes 0	

Response

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	
Document Name	

Comment

Many references in the requirements point toward Continuous Operating Region, Mandatory Operating Region, and Permissive Operating Region "as specified in **Attachment 1**", yet Attachment 1 does not specify any of these regions. Operating Regions should be added to Attachment 1 tables and figures.

No-trip zone Figures 1 & 2 don't match the tables.

Is there a point or distinction being made by using capitalized "Systen" instead of undefined "system" in requirements?

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	
Document Name	

Comment

The Implementation Plan should be extended to 36 months to allow for monitoring equipment to be installed at sites completed before PRC-029 becomes enforceable, to demonstrate performance and compliance with the standard.

Likes 0	
Dislikes 0	

Response

Dave Krueger - SERC Reliability Corporation - 10	
Answer	
Document Name	
Comment	

On behalf of the SERC Generator Working Group:

Consider allowing for some period of time beyond the effective date of PRC-029 to document limitations per (R6) – contemplate the real impact to BES reliability of limitation documentation.

Consider synchronizing the phase in of PRC-028 with the measures such as M1 stating "*shall have evidence of actual recorded data*...".

For each of the measures M1-M5, what "other evidence" can demonstrate compliance with R1-R5 other than recorded data? How does the drafting team believe that generator owners can assure this performance expectation can be achieved prior to an actual event? There is no test verification that can be performed to confirm the expected performance that considers every type of system disturbance that can occur.

Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	

OPG supports IESO, HQ, and NPCC Regional Standards Committee's comments.

Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	

MP agrees with the NSRF's suggestions to enhance PRC-029, especially regarding limiting the power of equipment limitations from exempting applicable entities from compliance, expanding the applicable facilities to include IBRs of 20MVA and above, and more precisely defining applicable entities and facilities within the text of the standard.

MP also suggests that a formal definition of "Inverter-Based Resources" precede the adoption of the standard.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5

Answer	
Document Name	

Comment

We are concerned that the standard refers to a defined term for IBR which has yet to be adopted in project 2020-06.

We suggest that the drafting team ensure consistent language is used in the section 4.2 "Facilities" section with the other projects such as 2021-04 (PRC-028) and 2023-02(PRC-030). Section 4.2.2 refers to IBR Registration criteria, however it is our understanding that section 4.2.1 would refer to GOs and TOs "that own equipment as identified in section 4.2" and where section 4.2 would indicate "the Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV." .

We question why "attachment 1" and "Requirement R6" are written in bold.

Attachment 1: should the "including, but not limited to" in table 2 include the same list (or minimally the same wording) that is found in the technical rationale of the IBR definition in project 2020-0?. For example, the IBR list in 2020-06 refers to "solar photovoltaic" whereas table 2 refers to "photovoltaic (PV)".

In what standard does the PC/TP define the applicable table in point 3 of section 2 in attachment 1? Same question for the voltage base for per unit calculation in both Attachment 1 and 2. Is there a corresponding requirement in another standard that requires the PC/TP to do this?

· Terms : Mandatory and permissive operation should be defined based on the attachment figures allowing for interconnections to use different requirements

· A-4.2.2 What is the IBR registration criteria? Add a clear reference and make sur the user understands what the IBR registration criteria is.

· B-R2-2.1 Attachment 1 only uses "no-trip zone". Define continuous operating region more clearly in the table (similar to what is done in PRC-024-4)

· B-R2-2.1.2 Can the TP ask for a mix of active/reactive power based on a predetermined ratio (currently only indicated as active or reactive).

· B-R2-2.2 Attachment 1 only uses "no-trip zone". Define "mandatory operation region" in Attachment 1.

· B-R2-2.4 Permissive operation region is not used or defined in attachment 1.

· B-R3. The document refers to an overvoltage value of 1.2pu. It should refer to a voltage exceeding the mandatory operating region in order for Interconnections to set their own overvoltage table.

· B-R3. Since R6 does not apply to this requirement, what will be done with existing IBR that cannot ride through these overvoltages ? An exemption clause is required for existing IBR that cannot be modified or upgraded.

· B-R4. The 5Hz/s value should be moved to Attachment 3 and B-R4 should only refer to the value in the Attachment.

· B-R4. Since R6 does not apply to this requirement, what will be done with existing IBR that cannot ride through these frequencies and ROCOF ? (for instance, for all the HQ connected projects, the ROCOF requirement was 4Hz/s) An exemption clause is required for existing IBR that cannot be modified or upgraded.

· B-R5. Since R6 does not apply to this requirement, what will be done with existing IBR that cannot ride through this phase angle jump ? An exemption clause is required for existing IBR that cannot be modified or upgraded.

· Attachment 1. Tables 1 and 2: Indicate what is considered as “continuous operation”, “mandatory operation” and “permissive operation” in an additional column.

· Attachment 1. HQ needs a Quebec regional variance since the Québec Interconnection has its own requirements in this regard.

· Attachment 2. Bullet 3: This sentence is hard to read. Proposed replacement: "Each IBR shall not trip unless the cumulative time of one or more instances in which the instantaneous voltage exceeds the respective voltage threshold over a 1-minute time window exceeds the minimum ride-through time"

· Attachment 2. HQ needs a Quebec regional variance since the Québec Interconnection has its own requirements in this regard.

· Attachment 3. This attachment should also include the maximum absolute ROCOF value.

· Attachment 3. HQ needs a Quebec regional variance (or the equivalent through the “regie de l’energie” approval process).

· B-R2-2.1.2 Which entity between Transmission Planner, Planning Coordinator, Reliability Coordinator and Transmission Operator has priority to specify those requirements?

· B-R2-2.4 Which entity between Transmission Planner, Planning Coordinator, Reliability Coordinator and Transmission Operator has priority to specify those requirements?

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	

The implementation plan is also very aggressive and for some generators may be impossible to meet.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Maozhong Gong - GE - GE Wind - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

Overall comments:

1. Implementation date: 6 months is not sufficient for IBR manufacturers to meet the new standard. Instead we propose 2yrs to accommodate product development/adequacy and appropriate validation.

2. For R6, R3,R4,R5 should be included as well for the documented limitation communication (see R6 comments below).

3. For Attachment 1, for VSC-HVDC connected IBRs, it is not clear if Table 2 is applicable at the MPT on grid side or on the IBR side of HVDC (see Attachment 1 comments below)

4. For MFRT, GEV suggests to align to IEEE2800-2022 7.2.2.4 for consistency (see Attachment 1 comments below).

GEV comments to R6: The language in R6 only allows documented limitations for Requirements R1 and R2. The standard must allow for documentation of limitations for Requirements R3, R4, and R5, as some existing site equipment was not designed to these requirements originally.

GEV comments to Table 2 in Attachment 1: For VSC-HVDC connected IBRs, please clarify if Table 2 is applicable at the MPT on grid side or on the IBR side.

GEV comments to MFRT: For MFRT requirements, GE Vernova strongly suggests that this language should align to IEEE2800-2022 7.2.2.4. Exceptions from the IEEE standard that are relevant were not included, making these requirements inconsistent with 2800-2022.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5

Answer	
Document Name	

Comment

PRC-24-4 mentined BPS in the Purpose section. We believe it is typo becuase the rest of the standard the applicabilty is for BES elements.

The implemetation plan to to strict to allow cost effect implementation.

Likes 0	
Dislikes 0	

Response

Imane Mrini - Austin Energy - 6, Group Name Austin Energy

Answer	
Document Name	

Comment

AE supports comments provided by Texas RE and the NAGF

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI offers the following additional comments on both PRC-024 & PRC-029:

PRC-029-1 (Applicability Section) Comments: EEI does not support the Applicability Section of PRC-029-1 for the following reasons:

1. Applicability details should not be contained in footnotes. Please remove footnote 1 from the Applicability Section.
2. Voltage Source Converter – High-voltage Direct Current (VSC-HVDC) are not defined or justified within the Technical Rationale as to why these resources need to be added PRC-029.
3. Without a justification of a need to include VSC-HVDC systems, TOs should be removed from PRC-029-1.
4. EEI does not support the use of the term "BPS IBRs" because no such term exists in the NERC Glossary of Terms that might provide entities with the knowledge to know definitively which IBRs are applicable.
5. EEI also does not support language that points to the registration criteria.

To address our concerns, we suggest the following changes to the Applicability Section of PRC-029-1, noting the Facilities portion of our comments utilize the recommendations from the Project 2020-06 SDT (see removals (i.e., TOs, registration criteria, etc. and other text) and boldface changes below:

4. Applicability:

4.1 Functional Entities:

4.1.1 Generator Owner

Facilities:

(1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

PRC-024 Comments: While there were no questions related to the proposed modifications to PRC-024-4, EEI does not support all of the proposed changes made to PRC-024-4. Note the following:

Applicability Section of PRC-024-4

EEI does not support changing the intent of 4.2.1.4 (Previously 4.2.1.5) to include multiple synchronous generators connecting to a common bus under the BES Definition, Inclusion I4. Since the development of the BES definition, Inclusion I4 did not include or intend to include synchronous generators. Had that been the intent, the SDT could have included synchronous generator resources in I4. Furthermore, the BES Reference Document states in Chapter I4: BES Inclusion the following:

Dispersed power producing resources are small-scale power generation technologies that use a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include, but are not limited to: solar, geothermal, energy storage, flywheels, wind, microturbines, and fuel cells.

While EEI is open to making modifications to the BES Definition, trying to provide interpretations within individual Applicability Sections of proposed NERC Reliability Guidelines is not the proper method to make such a change. For this reason, and since 4.2.1.4 (previously 4.2.1.5) was intended to address IBRs; this part of the Applicability Section of PRC-024-4 should be deleted.

Comments on the proposed New Definitions

EEI has no concerns with the proposed new definitions, but we do have some non-substantive comments on their usage throughout PRC-029, Implementation Plan and Technical Rationale. (See below)

- Usage of the newly defined terms deviated from the defined term within PRC-029 and the Technical Rational. (i.e., Operating vs. Operations)
- Incorrectly stating in the Implementation Plan that there were no newly defined terms. Please correct this error.

Continuous Operating Region – Only used once in Requirement 2.3.

- Continuous Operation Region used in Requirements 2.1, 2.1.2, 2.4, & once in Attachment 1 (i.e., suggest changing the defined term to Continuous **Operation** Region or correct to Continuous **Operating** Region throughout)
- Continuous Operation Region used twice in the Technical Rationale; Continuous Operating Region never used in the Technical Rationale.

Mandatory Operating Region – Never used in PRC-029

- Mandatory Operation Region used in PRC-029 in Requirements 2.2, 2.3, 2.4 & once in Attachment 1 (i.e., suggest changing the defined term to Mandatory **Operation** Region or correct to Mandatory **Operating** Region throughout)
- Mandatory Operation Region was used twice in Technical Rationale; Mandatory Operating Region was never used in the Technical Rational.

Permissive Operating Region – Never used in PRC-029

- Permissive Operation Region used in PRC-029 in Requirements 2.3, 2.4, & used twice in Attachment 1 (i.e., suggest changing the defined term to Permissive **Operation** Region or correct to Permissive **Operating** Region throughout)

- Permissive Operation Region used once in the Technical Rationale; Permissive Operating Region never used in the Technical Rationale.

Likes 0	
Dislikes 0	

Response	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	
Document Name	
Comment	

1. Implementation should align with PRC-028-1 proposed implementation to ensure data collecting information is available to adhere to PRC-029-1.

2. PRC-024-4 Applicability and Purpose should include asynchronous type 1 and type 2 wind since these are not IBRs and therefore not applicable to PRC-029:

4.2.1.4 Elements that are designed primarily for the delivery of capacity from the multiple synchronous generators ***or asynchronous type 1 or type 2 wind generators,*** connecting to a common bus identified in the BES Definition, Inclusion I4, to the point where those resources aggregate to greater than 75 MVA.

4.2.1.6 Type I and type II asynchronous wind generation identified in the BES Definition, Inclusion I4.

3. Suggest that the drafting team ensure consistent language is used in the section 4.2 “Facilities” section with the other projects such as Project 2021-04 (PRC-028) and 2023-02(PRC-030). We suggested the following language be included in the applicability section. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	

Please consider using the risk-based approach when drafting standards.

Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	

Duke Energy recommends the implementation of EEI and NAGF comments.

For clarification, expand the following subparts as stated below:

4.1. Functional Entities:

4.1.1. Transmission Owner that owns equipment as identified in section 4.2.

4.1.2. Generator Owner that owns equipment as identified in section 4.2.

4.2. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	

The applicability section should match applicability sections of other IBR standards under development, PRC-030 and PRC-028.

Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	

Comment
The NAGF provides the following additional comments for consideration: *PRC-024:* *a. Section 4.2.1.2 – Consider adding the language "Main Power Transformer (MPT)".* *b. Section 4.2.1.4 and 4.2.1.5 - Recommend that the proposed language be modified to reference BES Definition – Inclusion I2 instead of Inclusion I4 – Dispersed Power Producing Resources. The proposed new PRC-029 standard's focus is on Frequency and Voltage Ride-through Requirements for Inverter-Based Generating Resources and therefore should include a reference BES I4 resources.* *PRC-029:* *a. Terms – the NAGF requests additional clarification on how the proposed defined terms work with the proposed PRC-030. Will analysis be required for an event under the proposed PRC-029 and under PRC-030? Potential double jeopardy issue. Alternatively, if tripping is allowed under PRC-029, would an analysis still be required under PR-030?* *b. Section 4.2 - Facilities:* *i. Use of the capitalized term "Bulk Power System (BPS) Inverter-Based Resources (IBR)" should be reviewed as it is not a defined term in the NERC Glossary of Terms. In addition, it is very likely that not all Bulk Power System Inverter-Based Resources will be registered even under NERC's modified Rules of Procedure. Until the definition of Inverter-Based Resources is approved, the SDT should only use the term "inverter-based resource" if needed.* *ii. The NAGF requests clarification if IBR plants that include synchronous condensers should meet the PRC-029 requirements.* *c. Comments Related to Attachments:* *i. Attachment 1 – Recommend adding to the table a column that species what area is the Continuous Operating Region, Mandatory Operating Region and Permissive Operating Region. As currently structured, it is not clear where the different regions begin or end. If possible, the NAGF recommends a graph showing the different areas for clarity.* *ii. The abbreviations "MPT" and "ESS" are not defined within the standard/attachment. Please ensure all acronyms/initializations are fully defined for use.* *iii. If the term ESS is intended to mean Energy Storage Systems, does this also apply to water storage systems, or only Battery Energy Storage Systems? If the intent is to refer to Battery Energy Storage Systems, please modify the term used.* *iv. Attachment 1, note 3 – There does not appear to be a requirement proposed for the Transmission Planner (TP) to provide direction as stated in note 3. Request clarification on how the TP will provide such guidance/direction on the applicable table to be used.* *v. Attachment 1, Note 7 – These notes appear to state that no unit should trip in a 10 second period if voltage is fluctuating, but the summation of time interval does not appear to be 10 seconds in most instances. As an example, assuming that the SDT intends for a generator to follow the voltage for 10 seconds when it is fluctuating between .7 and .5, the unit should be allowed to trip when voltage is below the .5 level*

for 1.2 seconds. However, note 7 appears to state that there is a 10 second limit if voltage were to be below .7 for 1 second, then goes below .5 for 3 seconds, then returns to the .7 for 6 seconds. Please verify this interpretation is correct, or how this language should be understood.

vi. Attachment 1, Notes 7 and 8 – Both of these items discuss cumulative numbers in Tables 1 and 2. As worded, it is unclear if the intent is to add the numbers in Table 1 to the numbers in Table 2, or if the intent is to add the numbers in the second column of Table 1 for those resources that are considered Table 1 entities, and similar for Table 2 entities. Please clarify the wording so the intent of the standard is clear.

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	
Document Name	

Comment

AZPS supports the following comments that were submitted by EEI on behalf of its members:

PRC-029-1 (Applicability Section) Comments: EEI does not support the Applicability Section of PRC-029-1 for the following reasons:

1. Applicability details should not be contained in footnotes. Please remove footnote 1 from the Applicability Section.

2. Voltage Source Converter – High-voltage Direct Current (VSC-HVDC) are not defined or justified within the Technical Rationale as to why these resources need to be added PRC-029.

3. Without a justification of a need to include VSC-HVDC systems, TOs should be removed from PRC-029-1.

4. EEI does not support the use of the term "BPS IBRs" because no such term exists in the NERC Glossary of Terms that might provide entities with the knowledge to know definitively which IBRs are applicable.

5. EEI also does not support language that points to the registration criteria.

To address our concerns, we suggest the following language in the Applicability Section of PRC-029-1, noting the Facilities portion of our comments utilize the recommendations from the Project 2020-06 SDT):

4. Applicability:

4.1 Functional Entities:

4.1.1 Generator Owner

4.2 Facilities: (1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

PRC-024 Comments: While there were no questions related to the proposed modifications to PRC-024-4, EEI does not support all of the proposed changes made to PRC-024-4. Note the following:

Applicability Section of PRC-024-4

EEI does not support changing the intent of 4.2.1.4 (Previously 4.2.1.5) to include multiple synchronous generators connecting to a common bus under the BES Definition, Inclusion I4. Since the development of the BES definition, Inclusion I4 did not include or intend to include synchronous generators. Had that been the intent, the SDT could have included synchronous generator resources in I4. Furthermore, the BES Reference Document states in Chapter I4: BES Inclusion the following:

Dispersed power producing resources are small-scale power generation technologies that use a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include, but are not limited to: solar, geothermal, energy storage, flywheels, wind, microturbines, and fuel cells.

While EEI is open to making modifications to the BES Definition, trying to provide interpretations within individual Applicability Sections of proposed NERC Reliability Guidelines is not the proper method to make such a change. For this reason, and since 4.2.1.4 (previously 4.2.1.5) was intended to address IBRs; this part of the Applicability Section of PRC-024-4 should be deleted.

Comments on the proposed New Definitions

EEI has no concerns with the proposed new definitions, but we do have some non-substantive comments on their usage throughout PRC-029, Implementation Plan and Technical Rationale. (See below)

- Usage of the newly defined terms deviated from the defined term within PRC-029 and the Technical Rational. (i.e., Operating vs. Operations)

- Incorrectly stating in the Implementation Plan that there were no newly defined terms. Please correct this error.

Continuous Operating Region – Only used once in Requirement 2.3.

- Continuous Operation Region used in Requirements 2.1, 2.1.2, 2.4, & once in Attachment 1 (i.e., suggest changing the defined term to Continuous Operation Region or correct to Continuous Operating Region throughout)
- Continuous Operation Region used twice in the Technical Rationale; Continuous Operating Region never used in the Technical Rationale.

Mandatory Operating Region – Never used in PRC-029

- Mandatory Operation Region used in PRC-029 in Requirements 2.2, 2.3, 2.4 & once in Attachment 1 (i.e., suggest changing the defined term to Mandatory Operation Region or correct to Mandatory Operating Region throughout)
- Mandatory Operation Region was used twice in Technical Rationale; Mandatory Operating Region was never used in the Technical Rational.

Permissive Operating Region – Never used in PRC-029

- Permissive Operation Region used in PRC-029 in Requirements 2.3, 2.4, & used twice in Attachment 1 (i.e., suggest changing the defined term to Permissive Operation Region or correct to Permissive Operating Region throughout)
- Permissive Operation Region used once in the Technical Rationale; Permissive Operating Region never used in the Technical Rationale.

Likes 0	
Dislikes 0	

Response

Joy Brake - Nova Scotia Power Inc. - NA - Not Applicable - NPCC

Answer	
Document Name	

Comment

If using ALL CAPS, consider RCF as the acronym. It is not that significant a metric to require capitalization of "of".

RoCoF is also used in many other jurisdictions.

FERC order:

"In other words, under certain conditions some IBRs cease to provide power to the Bulk-Power System due to how they are configured and programmed. " Yes, but PRC-024 now prohibits this. In some cases, settings in the older plants can be tweaked to improve performance but we are having trouble getting good models from the GOs. To address NERC concerns we need requirements for better models.

"some models and simulations incorrectly predict that some IBRs will ride through disturbances, i.e., maintain real power output at pre-disturbance levels and provide voltage and frequency support consistent with Reliability Standard PRC-024-3". Only if incorrectly modelled. Require better modelling to identify issues and determine mitigations. PRC-029 will not stop the problem of simulating a system that works great in the virtual world but will not perform when called upon.

Likes 0	
Dislikes 0	

Response

Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC

Answer	
Document Name	

Comment

PNM agrees with EEI's comments.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE has the following additional comments for PRC-029-1:

1. Texas RE recommends the new terms included in PRC-029-1 clearly state the voltage measurements included are at the high-side of the main transformer connecting to the BPS transmission system. Texas RE suggests the following changes (in bold):

Term(s): Continuous Operating Region – The range of voltages, measured at the high-side of the **BPS** main power transformer, that are ≥ 0.9 per unit and ≤ 1.1 per unit.

Mandatory Operating Region – The range of voltages, measured at the high-side of the **BPS** main power transformer, that are > 0.1 per unit and < 0.9 per unit – or – > 1.1 and ≤ 1.2 per unit.

Permissive Operating Region – The range of voltages, measured at the high-side of the **BPS** main power transformer, that is ≤ 0.1 per unit.

2. Consider changing ‘each IBR’ to ‘each IBR Facility’ for all the requirements.

3. For consistency, consider modifying the title of the standard to (in bold):

Title: Frequency and Voltage Ride-through Requirements for Inverter-Based **Generating** Resources

4. Consider changing 4.2.1 to **BES** IBRs (instead of BPS IBRs) to be consistent with other PRC standards such as proposed reliability standards PRC-028-1 and PRC-024-4.

5. Consider changing voltage (per unit) in Attachment 1 (third row) to greater than 1.05 pu only (i.e. remove the equal 1.05 criterion). Typical BES and BPS systems are expected to operate continuously for voltage levels 0.95 – 1.05 pu.

Attachment 1 - changes

In Table 1 & Table 2 change > 1.05 to >1.05

Add the following to Table 1 and 2:

Voltage (per unit): > 0.9 Minimum Ride-Through: Continuous

Voltage (per unit): < 1.05 Minimum Ride-Through: Continuous

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	
Document Name	

Comment

- GTC recommends increasing the implementation timeline to be 12 to 18 months after the effective date of the applicable governmental authority’s order approving for both the PRC-024-4 and PRC-029-1 standards.

- There were no balloting questions provided for the language changes in the PRC-024-4 standard. GTC recommends providing balloting questions for the industry to respond to the changes in the PRC-024-4 standard.

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	
Document Name	

Comment

NERC should remain consistent with their revised Rules of Procedure by avoiding the use of “BPS IBR” terminology in the applicable facilities. This is overly broad and can lead to misinterpretation for Generator Owners who own IBRs that do and do not fit the 60 kV and 20 MVA thresholds. The third question in the Project 2020-06 comment form, copied below, is a clearer definition of IBR which NERC has determined has a material impact to the BPS. NERC should consider adopting this terminology in PRC-029

Section 4. Applicability:

4.1 Functional Entities: Generator Owner, Generator Operator

4.2 Facilities: (1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and North American Generator Forum (NAGF) on question 4

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	
Document Name	

Comment

Dominion Energy supports EEI comments. In addition, we have the following coments:

The term BPS IBRs and IBR Registration Criteria are not clear-cut Facilities. The standard should reference terms available for use in the NERC Glossary of Terms to determine applicability, such as the BES defintion. As stated in the EEI comments, the BES defintion would be the appropriate place to address defintions of this type.

The Effective Date of 6 months following approval by FERC is too short for Generator Owners and Transmission Owners that own numerous IBR generating sites, to develop internal controls and processes; and perform the necessary compliance evaluations and possible settings changes to meet the ride-through criteria. Conversely, 6 months after the effective date is too long for documenting Limitations per Requirement R6.

The documentation of limitations is typically done during the compliance analysis and study. A staggered implementation plan, that takes into account the registration and requirements for Level 2 GO registrations should be designed and implemented.

The Implementation Plan should also consider those IBRs that are approved to be built and have had their Interconnection Studies approved. The contracts for building these sites are signed years in advance with the inverters ordered. A staggered applicability for R6 should be considered that allow for projects in service prior to 2027 or 2028 to be eligible for equipment limitations and those in service after to meet the performance criteria without limitations.

Likes 0	
Dislikes 0	

Response

George E Brown - Pattern Operators LP - 5

Answer	
Document Name	

Comment

Pattern Energy supports GRE's comments for this question.

Likes 0	
Dislikes 0	

Response

Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies

Answer	
Document Name	

Comment

The SDT explains in the draft PRC-029-1 Technical Rationale that "An IBR becomes noncompliant with PRC-029 only when an event in the field occurs that shows that one or more requirements were not satisfied." This, coupled with the removal of IBRs from PRC-024 applicability, would result in a lack of accountability until actual harm (i.e., failure to adequately support the reliability of the BES during a system event) occurs for IBRs not prepared to meet the performance requirements. There would not be auditable and enforceable requirements for owners of IBRs to proactively take action to reasonably ensure the performance requirements will be met. Reliability standards exist to prevent potential harm, which minimizes actual harm.

While RF acknowledges the observed limitations of the existing PRC-024 standard in preventing the undesirable responses of IBRs to the system disturbance events cited in the SAR, RF does not support the whole-sale elimination of frequency and voltage protection settings verification requirements for IBRs. Generator frequency protection settings verification is critical in ensuring UFLS programs are adequately coordinated with generator capabilities, and RF does not wish to rely on self-revealing events to determine where miscoordination exists between IBR frequency protection and UFLS. Unless additional verification requirements are added to PRC-029, RF believes PRC-024 should remain applicable to IBRs.

RF notes that the range of system conditions in which PRC-029 would require IBRs to remain online appear to be significantly larger than those established in PRC-024 (which would remain applicable to synchronous generators). Although the unique capabilities of IBRs may support such a large expansion for only IBR resource types, additional discussion of the technical justification for this expansion would be useful.

Regarding implementation, RF finds a 12-month implementation period acceptable.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment

The implementation plan is also very aggressive and for some generators may be impossible to meet.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	
Document Name	

Comment

- The new performance-based approach opens us up to a lot of issues with other tripping/cessation besides basic overvoltage/under voltage/frequency that our operations team has seen during events.
    - This protection is not modeled in basic models right now and will require substantial effort to ensure we can perform as required. AES CE requests that the Implementation Plan be modified to use a phased-in approach for existing sites to allow adequate time to prepare for these performance requirements.

Additionally, the standard and rationale is absent of language on studies/assessments that should be performed. AESCE believes that providing examples of the types of studies and assessments that should be run to ensure that resources would perform as expected is necessary for reliability and adequate implementation of this standard by GOs.

- Please provide additional clarification on acceptable limitations under R6. Language such as “hardware replacements or other costly upgrades” from the Technical rationale document is vague and open to interpretation.
- AESCE would like the SDT to consider the challenges with ensuring plants, particularly legacy operational plants, can ride through per the requirements. To ensure this or identify equipment limitations, studies and equipment information is necessary and is not available for most legacy equipment.
- First, EMT studies and RMS model studies are necessary to study plant ride-through capabilities specified in the standard. However, there are significant challenges with these models today that should be considered in the implementation and equipment limitations. Quality EMT models including all equipment information needed are not available for legacy equipment (inverters, PPCs). Many legacy inverters do not have an EMT model, and those that do have models that are not adequately validated against equipment performance. Creation of models is either not supported or can be developed at a very high cost. Models created after the inverters were initially released are of inadequate quality because the equipment is no longer able to be in a lab environment.
    - To consider this, AESCE suggests that the SDT include exceptions for legacy equipment where the performance may not be predictable due to a lack of modeling or inverter information.
- Second, not all current models are of the level of quality that they can be used to ensure that the plant will ride-through as specified in the standard. The implementation of this standard should consider the significant resources and cost to implement.
- Third, manufacturer support for GOs to ensure that IBRs only trip to prevent equipment damage as noted in R2.5 is limited for existing equipment and is unavailable for some legacy equipment. Additionally, this support has been very costly for us to obtain and will strain manufacturer resources to provide.

Considering these limitations, AESCE suggests that the SDT include exceptions for legacy equipment where 1. The performance may not be predictable due to a lack of accurate models at a reasonable cost, 2. Equipment limits may not be known or where the cost may be egregious to provide.

- Expectations for demonstrating and checking performance are unclear, please add language or examples to illustrate how the SDT believes this will happen.

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5

Answer	
Document Name	

Comment

Invenergy thanks the drafting team for their work and the opportunity to provide comments.

Regarding the proposed Implementation Plan for R6, six months may not be enough time to gather all applicable documentation regarding equipment limitations. There are a limited number of vendors of IBR technology that have serviced the industry, and they will be inundated with requests for documentation once the standard becomes effective.

On a final note, NERC appears to have borrowed from some of the requirements within IEEE 2800-2022 and brought them into this standard (e.g. the phase-angle jump requirement, etc.). Invenergy believes it would be incorrect to adopt such requirements until the work of IEEE Working Group p2800.2 has been completed and their recommended practice standard published. Without such an approved recommended practice standard, there is no industry-wide accepted set of procedures for verifying conformity to the borrowed requirements in PRC-029-1.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 1,3,6

Answer	
Document Name	

Comment

Ameren agrees with EEI's comments.

In addition, Ameren believes that ride-through requirements should be in a MOD standard instead of a PRC standard. Protection relay engineers do not have access to the necessary IBR equipment and do not have the expertise to determine the root cause of why an IBR behaved in an unexpected manner. Thus, evaluating and establishing a CAP to correct a reduction in power following a disturbance will not be performed by a relay engineer.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	
Document Name	

Comment

Invenergy thanks the drafting team for their work and the opportunity to provide comments.

Regarding the proposed Implementation Plan for R6, six months may not be enough time to gather all applicable documentation regarding equipment limitations. There are a limited number of vendors of IBR technology that have serviced the industry, and they will be inundated with requests for documentation once the standard becomes effective.

On a final note, NERC appears to have borrowed from some of the requirements within IEEE 2800-2022 and brought them into this standard (e.g. the phase-angle jump requirement, etc.). Invenergy believes it would be incorrect to adopt such requirements until the work of IEEE Working Group p2800.2 has been completed and their recommended practice standard published. Without such an approved recommended practice standard, there is no industry-wide accepted set of procedures for verifying conformity to the borrowed requirements in PRC-029-1.

Likes 0	
Dislikes 0	

Response

Brittany Millard - Lincoln Electric System - 5

Answer	
Document Name	

Comment

With regards to PRC-029 we woulkd ask:

1. Clarify and emphasize that limitations must not be construed as complete exemptions. If entities are unable to ride-through portions of the ride-through curve, this does not automatically exempt them from complying with the balance of the ride-through curve as described in the Technical Rationale. While this is clear in the Technical Rationale for Requirement R6 (page 9), this point needs to be brought out more clearly in the PRC-029 standard itself.

2. Expand PRC-029 to require Corrective Action Plans be implemented to remove equipment limitations within a specified timeline.

3. we recommend modifying Section 4 of PRC-029-1 as follows:

4. Applicability:

4.1 Functional Entities: 4.1.1 Generator Owner that owns equipment identified in section 4.2, 4.1.2 Transmission Owner that owns equipment as identified in section 4.2 Generator Owner that owns equipment identified in section 4.2.

4.2 Facilities: to include 4.2.3 Shunt static or dynamic reactive device(s) associated with IBR that either have or contribute to meeting the performance requirements.

4. The standard is event-based compliance that requires installing recorded equipment data with higher sampling rates at all applicable legacy IBR Facilities. Therefore, we suggest that the implementation plan for PRC-029 should be aligned with Project 2021-04 (PRC-028-1) for the legacy IBR. Also, we suggest having a different implementation plan for the legacy IBR from IBR connected after the approval date of PRC-029.

5. Some clarity on how these requirements would be enforced in the location where no data recording is available at the IBR facility during system events.

6. M1-M5 required GO to maintain the evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in Requirement R1-R5. What are the criteria for selecting the event(s) that should be analyzed to demonstrate compliance with the VRT, FRT, and VRT performance requirement(s)? If the performance does not meet the requirement(s), do Generator Owner needs to present a correction action plan and provide it to each applicable Reliability Coordinator. We suggest coordinate this project 2020-02 (PRC-029) with project 2023-02(PRC-030) regarding the IBR ride-through performance analysis.

7. We suggest that the drafting team ensure consistent language is used in the section 4.2 “Facilities” section with the other projects such as Project 2021-04 (PRC-028) and 2023-02(PRC-030). We suggested the following language be included in the applicability section. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

8. The title of the standard calls out “Inverter-Based Generating Resources”, should “Generating” be removed to be consistent?

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	
Document Name	

Comment

Several enhansments to PRC-029 are requested:

1. **Clarify and emphasize that limitations must not be construed as complete exemptions.** If entities are unable to ride-through portions of the ride-through curve, this does not automatically exempt them from complying with the balance of the ride-through curve as described in the Technical Rationale. While this is clear in the Technical Rationale for Requirement R6 (page 9), this point needs to be brought out more clearly in the PRC-029 standard itself.
2. **Expand PRC-029 to require Corrective Action Plans be implemented to remove equipment limitations within a specified timeline**.
3. **we recommend modifying Section 4 of PRC-029-1 as follows:**

4. Applicability:

4.1 Functional Entities: 4.1.1 Generator Owner that owns equipment identified in section 4.2, 4.1.2 Transmission Owner that owns equipment as identified in section 4.2 Generator Owner that owns equipment identified in section 4.2.

4.2 Facilities: to include 4.2.3 Shunt static or dynamic reactive device(s) associated with IBR that either have or contribute to meeting the performance requirements.

4. **The standard is event-based compliance that requires installing recorded equipment data with higher sampling rates at all applicable legacy IBR Facilities. Therefore, we suggest that the implementation plan for PRC-029 should be aligned with Project 2021-04 (PRC-028-1) for the legacy IBR. Also, we suggest having a different implementation plan for the legacy IBR from IBR connected after the approval date of PRC-029.**
5. **Some clarity on how these requirements would be enforced in the location where no data recording is available at the IBR facility during system events.**
6. **M1-M5 required GO to maintain the evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in Requirement R1-R5. What are the criteria for selecting the event(s) that should be analyzed to demonstrate compliance with the VRT, FRT, and VRT performance requirement(s)? If the performance does not meet the requirement(s), do Generator Owner needs to present a correction action plan and provide it to each applicable Reliability Coordinator. We suggest coordinate this project 2020-02 (PRC-029) with project 2023-02(PRC-030) regarding the IBR ride-through performance analysis.**
7. **We suggest that the drafting team ensure consistent language is used in the section 4.2 "Facilities" section with the other projects such as Project 2021-04 (PRC-028) and 2023-02(PRC-030). We suggested the following language be included in the applicability section. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.**

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

New terms are introduced on page 2 (Continuous **Operating** Region, Mandatory **Operating** Region, Permissive **Operating** Region). Requirement R1 includes the words "**operation** regions" and R2 includes the terms "Continuous **Operation** Region" (Part 2.1) and "Mandatory **Operation** Region" (Part 2.2). We recommend the drafting team review all instances of "**operation** region" within the standard and determine if it should be changed to "**operating** region" to align with the proposed terms. Or conversely, consider if the word "Operating" within the defined terms should be changed to "Operation".

For Requirement R2:

How will the Generator Owner or Transmission Owner of an applicable IBR be made aware that a PRC-029-1 applicable "System disturbance" has occurred within their associated Planning Coordinator(s) area(s)?

Part 2.1.2 refers to "requirements [for active or reactive power preference] specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator".

Part 2.2.2 refers to a "certain magnitude of reactive power response to voltage changes" or a preference for "active power priority instead of reactive power priority" that can be specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Part 2.4 refers to a "lower post-disturbance active power level requirement" or "different post-disturbance active power restoration time" specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

With up to four registered entity types being able to provide these preferences (spanning the operations and planning time horizons), is there a chance the Generator Owner or Transmission Owner of an applicable IBR will receive conflicting requirements? Is there a corresponding standard(s) that includes a requirement(s) for the TP, PC, RC or TOP to specify these preferences?

For Requirement R3, how will the Generator Owner or Transmission Owner of an applicable IBR know that a PRC-029-1 applicable transient overvoltage period has occurred within their associated Planning Coordinator(s) area(s)?

For Requirement R4, how will the Generator Owner or Transmission Owner of an applicable IBR know that a PRC-029-1 applicable frequency excursion event has occurred within their associated Planning Coordinator(s) area(s)?

Requirement R6 requires that a Generator Owner or Transmission Owner of an applicable IBR that has a documented equipment limitation, that prevents it from meeting voltage ride-through requirements as detailed in Requirements R1 and R2, communicate each equipment limitation to their associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s). Since the Transmission Operator is also identified in R2, it seems strange to omit the TOP from R6.

With regard to the Implementation Plan, having PRC-024-4 becoming effective six months after approval is reasonable, since this Standard's changes are primarily to limit its applicability to synchronous generators / condensers, and they should already be compliant with the existing version.

However, having PRC-029-1 become effective six months after approval is not reasonable. The technical rationale doesn't provide guidance on how to provide evidence of compliance. It can take considerable time to develop and perform the required analyses, generate potential design changes to make the required setting changes, and implement them.

We recommend providing implementation guidance or technical data showing how to demonstrate performance.

We also recommend allowing at least 24 months to achieve full compliance with the proposed requirements in PRC-029-1.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	
Document Name	

Comment

Black Hills Corporation supports EEI's and NAGF's additional comments.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	

Comment

FirstEnergy finds inconsistency in how these newly created standards are applying IBR applicability in the Applicable Section – leading to confusion from one project and standard to another. We request these Drafting Teams align these Applicable Sections.

FE cannot support the Implementation Plan until it is clear how R2 will be clarified toward requirement responsibility.

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	
Document Name	

Comment

AECI supports comments provided by the NAGF

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	

Document Name	
Comment	

The language proposed in the Applicability section of PRC-029-1 is inadequate to define what IBR Facilities this Standard would apply to. The terms “BPS IBRs” and “IBR Registration Criteria” are too broad, vague, and undefined, and could include all IBRs interconnected to the Bulk Power System at any voltage level.

SMUD recommends the Standards Drafting Team use similar language to that proposed in NERC Standards Project 2021-04 Modifications to PRC-002 - Phase II, PRC-028-1 draft #2. If modified accordingly, the Applicability section would state:

“4.1. Functional Entities:

4.1.1. Generator Owner that owns equipment as identified in section 4.2

4.1.2. Transmission Owner that owns equipment as identified in section 4.2

4.2. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.”

Likes 0	
Dislikes 0	
Response	

Brian Lindsey - Entergy - 1

Answer	
Document Name	
Comment	

No Comment

Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	
Document Name	
Comment	

NA	
Likes 0	
Dislikes 0	
Response	
Michael Brytowski - Great River Energy - 3	
Answer	
Document Name	
Comment	

1. Clarify and emphasize that limitations must not be construed as complete exemptions. If entities are unable to ride-through portions of the ride-through curve, this does not automatically exempt them from complying with the balance of the ride-through curve as described in the Technical Rationale. While this is clear in the Technical Rationale for Requirement R6 (page 9), this point needs to be brought out more clearly in the PRC-029 standard itself.

2. Expand PRC-029 to require Corrective Action Plans be implemented to remove equipment limitations within a specified timeline.

3.. **we recommend modifying Section 4 of PRC-029-1 as follows:**

4. Applicability:

4.1 Functional Entities: 4.1.1 Generator Owner that owns equipment identified in section 4.2, 4.1.2 Transmission Owner that owns equipment as identified in section 4.2 Generator Owner that owns equipment identified in section 4.2.

4.2 Facilities: to include 4.2.3 Shunt static or dynamic reactive device(s) associated with IBR that either have or contribute to meeting the performance requirements.

4. **The standard is event-based compliance that requires installing recorded equipment data with higher sampling rates at all applicable legacy IBR Facilities. Therefore, we suggest that the implementation plan for PRC-029 should be aligned with Project 2021-04 (PRC-028-1) for the legacy IBR. Also, we suggest having a different implementation plan for the legacy IBR from IBR connected after the approval date of PRC-029.**

5. **Some clarity on how these requirements would be enforced in the location where no data recording is available at the IBR facility during system events.**

6. M1-M5 required GO to maintain the evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in Requirement R1-R5. What are the criteria for selecting the event(s) that should be analyzed to demonstrate compliance with the VRT, FRT, and VRT performance requirement(s)? If the performance does not meet the requirement(s), do Generator Owner needs to present a correction action plan and provide it to each applicable Reliability Coordinator. We suggest coordinate this project 2020-02 (PRC-029) with project 2023-02(PRC-030) regarding the IBR ride-through performance analysis.

7. We suggest that the drafting team ensure consistent language is used in the section 4.2 “Facilities” section with the other projects such as Project 2021-04 (PRC-028) and 2023-02(PRC-030). We suggested the following language be included in the applicability section. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	
Document Name	

Comment

BC Hydro appreciates the drafting team’s efforts and the opportunity to comment, and offers the following:

1. The Applicability section (A.4.2 Facilities) of PRC-029-1 references BPS IBR and IBR Registration Criteria. BC Hydro suggests that the Facilities section instead use wording reflective of the proposed Category 2 GO as included in the recent revisions to the NERC Rules of Procedure.
2. BC Hydro suggests that the use of “shall” in the language of the Measures may not be appropriate as it could imply a new Requirement or expansion on the existing Requirement. The obligation of having evidence is adequately established and enforceable via the CMEP.
3. The Measure M3 of PRC-029-1 references "the associated Planning Coordinator". The associated Requirement R3 does not. BC Hydro suggests that this is not needed as there may be switching events within a PC's area that do not create overvoltage conditions to trigger R3 for certain IBRs within the PC area.

Likes 0	
Dislikes 0	

Response

Helen Lainis - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment

Applicability:

In Introduction, Section 4.2.2, it is not obvious what aspect of 'IBR Registration Criteria' makes an IBR an 'applicable' IBR – is it simply that an IBR meets NERC Registration Criteria? This bullet point should be elaborated to ensure clarity.

Event-Based Standard:

The IESO has concerns with this standard being an event-based standard, in that it does not necessarily provide an assurance of reliability before events occur, such as would be provided by having an engineering analysis, or bench-testing/real-time simulations of controls equipment that indicates successful ride through of prescribed disturbances is expected.

Without disturbance events that challenge the IBRs to perform properly it would be unknown if the IBR is compliant. At a minimum, the measures (e.g, M2-M5) should be extended to allow a statement that no such events are known to have occurred to 'count' as evidence of compliance.

Presentation of Ride Through Ranges:

The intended ride through requirements could be made more clear if the 'minimum ride through times' were associated with precisely stated, *non-overlapping ranges* of voltages or frequencies, such as in the example 'Table 2' provided by the IESO in the comments above, for Section 2.1.

Nominal Voltages:

To ensure clarity of intent in note #4 of Attachment 1, the 'nominal' system voltage values should be listed as they are in the existing PRC-024, i.e., "(e.g., 100 kV, 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 400 kV, 500 kV, 765 kV, etc.)"

Harmonize Tables, Figures, Requirements:

The levels of voltage/frequency excursion and the minimum ride through times for all tables, figures, and any associated performance requirements that modify the requirements at given times should be carefully reviewed and harmonized. There are presently some conflicting entries in the tables/figures.

Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	

Response

Chantal Mazza - Hydro-Quebec (HQ) - 1 - NPCC

Answer	
Document Name	

Comment

We are concerned that the standard refers to a defined term for IBR which has yet to be adopted in project 2020-06.

We suggest that the drafting team ensure consistent language is used in the section 4.2 "Facilities" section with the other projects such as 2021-04 (PRC-028) and 2023-02(PRC-030). Section 4.2.2 refers to IBR Registration criteria, however it is our understanding that section 4.2.1

would refer to GOs and TOs “that own equipment as identified in section 4.2” and where section 4.2 would indicate “the Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.” .

We question why “attachment 1” and “Requirement R6” are written in bold.

Attachment 1: should the “including, but not limited to” in table 2 include the same list (or minimally the same wording) that is found in the technical rationale of the IBR definition in project 2020-0?. For example, the IBR list in 2020-06 refers to “solar photovoltaic” whereas table 2 refers to “photovoltaic (PV)”.

In what standard does the PC/TP define the applicable table in point 3 of section 2 in attachment 1? Same question for the voltage base for per unit calculation in both Attachment 1 and 2. Is there a corresponding requirement in another standard that requires the PC/TP to do this?

· Terms : Mandatory and permissive operation should be defined based on the attachment figures allowing for interconnections to use different requirements

· A-4.2.2 What is the IBR registration criteria? Add a clear reference and make sur the user understands what the IBR registration criteria is.

· B-R2-2.1 Attachment 1 only uses "no-trip zone". Define continuous operating region more clearly in the table (similar to what is done in PRC-024-4)

· B-R2-2.1.2 Can the TP ask for a mix of active/reactive power based on a predetermined ratio (currently only indicated as active or reactive).

· B-R2-2.2 Attachment 1 only uses "no-trip zone". Define "mandatory operation region" in Attachment 1.

· B-R2-2.4 Permissive operation region is not used or defined in attachment 1.

· B-R3. The document refers to an overvoltage value of 1.2pu. It should refer to a voltage exceeding the mandatory operating region in order for Interconnections to set their own overvoltage table.

· B-R3. Since R6 does not apply to this requirement, what will be done with existing IBR that cannot ride through these overvoltages ? An exemption clause is required for existing IBR that cannot be modified or upgraded.

· B-R4. The 5Hz/s value should be moved to Attachment 3 and B-R4 should only refer to the value in the Attachment.

· B-R4. Since R6 does not apply to this requirement, what will be done with existing IBR that cannot ride through these frequencies and ROCOF ? (for instance, for all the HQ connected projects, the ROCOF requirement was 4Hz/s) An exemption clause is required for existing IBR that cannot be modified or upgraded.

· B-R5. Since R6 does not apply to this requirement, what will be done with existing IBR that cannot ride through this phase angle jump ? An exemption clause is required for existing IBR that cannot be modified or upgraded.

· Attachment 1. Tables 1 and 2: Indicate what is considered as “continuous operation”, “mandatory operation” and “permissive operation” in an additional column.

· Attachment 1. HQ needs a Quebec regional variance since the Québec Interconnection has its own requirements in this regard.

· Attachment 2. Bullet 3: This sentence is hard to read. Proposed replacement: "Each IBR shall not trip unless the cumulative time of one or more instances in which the instantaneous voltage exceeds the respective voltage threshold over a 1-minute time window exceeds the minimum ride-through time"

· Attachment 2. HQ needs a Quebec regional variance since the Québec Interconnection has its own requirements in this regard.

· Attachment 3. This attachment should also include the maximum absolute ROCOF value.

· Attachment 3. HQ needs a Quebec regional variance

· B-R2-2.1.2 Which entity between Transmission Planner, Planning Coordinator, Reliability Coordinator and Transmission Operator has priority to specify those requirements?

· B-R2-2.4 Which entity between Transmission Planner, Planning Coordinator, Reliability Coordinator and Transmission Operator has priority to specify those requirements?

Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

- Evidence Retention: We would suggest that the evidence retention period for both Standards should be changed from five years to three years, to be consistent with other NERC Standards.

- The standard is event-based compliance that required installing recorded equipment data with higher sampling rates at all applicable legacy IBR Facilities. Therefore, we recommend that the implementation plan for PRC-029 should be aligned with Project 2021-04 (PRC-028-1) for the legacy IBR. Also, we suggest have different implementation plan for the legacy IBR from IBR connected after the approval date of PRC-029.

- Some clarity how these requirements would be enforced in a location where no data recording is available at an IBR facility during system events.

- M1-M5 required the GO to maintain the evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in Requirement R1-R5. What are the criteria for selecting the event(s) that should be analyzed to demonstrate compliance with the VRT, FRT and VRT performance requirement(s)? If the performance does not meet the requirement(s), do Generator Owner need to present a corrective action plan and provide it to each applicable Reliability Coordinator. We suggest coordinating this project 2020-02 (PRC-029) with project 2023-02(PRC-030) regarding the IBR ride-through performance analysis.

- R2: We agree with the present flexibility that some of the IBR VRT performance could be modified to meet the individual system needs by the applicable Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator. However, some clarity may be required on how this process is initiated and what type of evidence is required to demonstrate the request is received and implemented. This may be an additional requirement assigned to the Transmission Planner. Each Transmission Planner, Planning Coordinator, and Transmission Operator that jointly specifies the following voltage ride-through performance requirements within their area(s) different than those specified under R2, shall make those requirements available to each associated applicable IBR Generator Owner and Transmission Owner.

- We suggest that the drafting team ensures consistent language is used in the section 4.2 "Facilities" section with the other projects such as Project 2021-04 (PRC-028) and 2023-02(PRC-030). We suggest the following language be included in the applicability section. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

- R3: we suggest adding to the attachment 2 how the instantaneous transient overvoltage should be calculated (such as what is the pu based on? and the minimum sampling rate?)

Likes 0	
Dislikes 0	

Response

Leah Gully - Madison Fields Solar Project, LLC - 5 - RF

Answer	
Document Name	

Comment

1. The proposed Standard refers to four different operating regions (no-trip zone, Continuous Operation Region, Mandatory Operation Region, and Permissive Operating Region). The different zones require Generator Owners to take different actions based on the number of disturbances and deviations that occur within in a 10 second period as well as the positive sequence voltage on the high side of the MPT. The ability of plant operators or inverter controls to identify, track, and respond effectively to all these variables is unrealistic. Why are these requirements not applied to non-IBR owners?
2. In R1, GOs are required to ensure that IBRs continue to "exchange current in accordance with the no-trip zones and operation regions as specified in Attachment 1." The Standard does not define the term "exchange current". Please define this term.
3. Measure 1 requires the Generator Owner and Transmission Owner to have actual recorded data for each applicable IBR demonstrating ridethrough adherence. This measure needs a timeframe for retention of the data.
4. The second half of the sentence in 2.1.1 doesn't appear to add any value to the sub-requirement. Please clarify what added operational requirement is meant by, "…and continue to deliver active power and reactive power up to its apparent power limit."
5. Requirement R2.1.2 allows four different entities to dictate each IBR's operating mode. This contradicts the requirements of VAR-001 which states that GOs must operate in voltage control mode unless exempted by the TOP. Recommend selecting one of these entities to determine the preference.

6. For overvoltage conditions greater than 140% Attachment 2 requires Generator Owners to distinguish and respond with different time delays, all less than or equal to 3 ms. Recommend requiring IBRs to delay their response to voltage excursions and program their IBRs to match the responses of synchronous machines.
7. Clarify Requirement 2.2.1 to address the expected operational response to close-in faults. Recommend the Standard specify separate performance requirements for close-in faults and more distant faults.
8. Requirement 2.2 appears to mandate that IBRs who operate in active power priority mode in the continuous operating region would be required to switch to the reactive power mode if a voltage disturbance occurs. What criteria are IBRs expected to use to determine when this switch should occur? What are IBRs expected to do if their inverters cannot be switched without software modifications?
9. The ride through requirements should all be specified in the same units of time.
10. Couldn't the voltage overshoot concerns addressed by Requirement 2.3 be addressed more reliably by slowing the response time of the IBR plant controllers to match that of synchronous generation?
11. Measure 2 requires the GO and TO to have actual recorded data during each system disturbance. Recommend establishing a timeframe for the retention of this data.
12. Measure 3 requires the GO and TO to have actual recorded data during each transient voltage event. Recommend establishing a timeframe for the retention of this data.
13. Measure 4 requires the GO and TO to have actual recorded data during each frequency excursion event. Recommend establishing a timeframe for the retention of this data.
14. Measure 5 requires the GO and TO to have actual recorded data during each positive sequence voltage phase angle changes that are less than 25 electrical degrees at the high side of the main transformer. Recommend establishing a timeframe for the retention of this data.
15. Requirement 6 has more specific requirements for an equipment limitation than is being proposed for the synchronous generators. Recommend PRC-029 reflect the wording proposed for PRC-024-4.
16. PRC-029 frequency ride-through is a single graph for all regions. The graph no trip zone is larger than the existing PRC-024 frequency no-trip zone for Eastern, Western, and ERCOT zones. The wording in the rationale is very soft (may be required). The change will cause the LFRT and HFRT settings to be updated as well as collector and transformer frequency settings. Recommend the frequency settings remain consistent with PRC-024 until the time that it is justified from grid events.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	
Document Name	

Comment

In some cases, the initial 6-month implementation period to develop a technical rationale for an exemption may be too short. This is attributable to the necessary input from the original OEM and in some cases due to the complexity associated with facilities comprised of new and old equipment. One example where this may exist are plants where a repower project may have taken place that does not replace all inverters. In a case such as this, the new equipment may meet the requirements, but the remaining existing equipment may not. This may require a detailed study to verify compliance, or perhaps instead, require some form of hybrid exemption for the site. Unlike the stated technical goal of the standard where this is a “performance based” standard, the justification for a technical exemption will require some form of a study to justify that exemption. This could lead to a greater than 6-month period in developing the exemption request. To accommodate these situations, AEP recommends an implementation period of 18 months.

PRC-029 requires that IBR’s shall ride through 110%-120% overvoltage from 0-1 seconds as seen at the high side of the main power step-up transformer. Due to voltage drop, the voltage seen at the equipment terminals can be another 5% higher leading to potential equipment damage from overvoltage. AEP suggests that the SDT consider lowering the ride through to 110% at the high side of the main step-up transformer.

Likes 0	
Dislikes 0	

Response

Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	2020-02_EPRI Comments on Draft NERC PRC-029 (IBR ride-through) Reliability Standard.pdf

Comment

Likes 0	
Dislikes 0	

Response

Consideration of Comments

Project Name:	2020-02 Modifications to PRC-024 (Generator Ride-through) | Draft 1
Comment Period Start Date:	3/27/2024
Comment Period End Date:	4/22/2024
Associated Ballot(s):	2020-02 Modifications to PRC-024 (Generator Ride-through) Implementation Plan IN 1 OT 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-024-4 | Non-binding Poll IN 1 NB 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-024-4 IN 1 ST 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-029-1 | Non-binding Poll IN 1 NB 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-029-1 IN 1 ST

There were 79 sets of responses, including comments from approximately 180 different people from approximately 111 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, contact Director, Standards Development Latrice Harkness (via email) or at (404) 858-8088.

Questions

1. Do you agree with the need for creating a new Standard (PRC-029-1) to address gaps the Inverter-Based Resource Performance Subcommittee (IRPSC) identified within the PRC-024-3 Project 2020-02 SAR and to address the expectations of FERC Order No. 901?

2. Do you agree that the language within PRC-029-1 requirements R1, R2, and R6 regarding IBR plant-level performance during grid voltage disturbances is clear?

3. Do you agree with the drafting team's proposals for including IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in PRC-029-1 Requirements R3, R4, and R5?

4. Provide any additional comments for the Drafting Team to consider, if desired.

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
Santee Cooper	Carey Salisbury	1,3,5,6		Santee Cooper	Lachelle Brooks	Santee Cooper	1,3,5,6	SERC
					Paul Camilletti	Santee Cooper	1,3,5,6	SERC
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
Southern Company - Southern Company Services, Inc.	Colby Galloway	1,3,5,6	MRO,RF,SERC,Texas RE,WECC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company -	3	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Alabama Power Company		
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
California ISO	Darcy O'Connell	2	WECC	ISO/RTO Council (IRC) Standards Review Committee	Ali Miremadi	California ISO	2	WECC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Helen Lainis	Independent Electricity System Operator	2	NPCC
					Elizabeth Davis	PJM Interconnection	2	RF
					Charles Yeung	Southwest Power Pool, Inc.	2	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
Austin Energy	Imane Mrini	6		Austin Energy	Imane Mrini	Austin Energy	6	Texas RE
					Michael Dillard	Austin Energy	5	Texas RE
					Lovita Griffin	Austin Energy	3	Texas RE
					Tony Hua	Austin Energy	4	Texas RE
					Thomas Standifur	Austin Energy	1	Texas RE
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					John Nierenberg	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	SERC
					Sara Orr	Golden Spread Electric Cooperative, Inc.	5	Texas RE
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Micah Runner	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					David Kwan	Ontario Power Generation	4	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Chantal Mazza	Hydro Quebec	1,2	NPCC
					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Chantal Mazza	Hydro Quebec	1,2	NPCC
					Nicolas Turcotte	Hydro-Quebec (HQ)	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Joel Charlebois	AESI	7	NPCC
Elevate Energy Consulting	Ryan Quint	NA - Not Applicable	NA - Not Applicable	Elevate Energy Consulting	Ryan Quint	Elevate Energy Consulting		NA - Not Applicable
					N/A	N/A		NA - Not Applicable
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Stephen Whaite	Stephen Whaite		RF	ReliabilityFirst Ballot Body Member and Proxies	Lindsey Mannion	ReliabilityFirst	10	RF
					Stephen Whaite	ReliabilityFirst	10	RF
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Gary Dollins	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Olivia Olson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	SERC
					Heath Henry	NW Electric Power Cooperative, Inc.	3	SERC
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	KAMO Electric Cooperative	1	SERC
					Brett Douglas	Northeast Missouri	1	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Electric Power Cooperative		
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Mark Riley	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Chuck Booth	Associated Electric Cooperative, Inc.	5	SERC
					Jarrod Murdaugh	Sho-Me Power Electric Cooperative	3	SERC

1. Do you agree with the need for creating a new Standard (PRC-029-1) to address gaps the Inverter-Based Resource Performance Subcommittee (IRPSC) identified within the PRC-024-3 Project 2020-02 SAR and to address the expectations of FERC Order No. 901?

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
We recommend adding these IBR related requirements to PRC-024, rather than creating a new Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The need for a separate standard, PRC-029, is a consequence of both the different natures of synchronous and inverter-based generation and several recent events exhibiting significant IBR ride-through deficiencies and failures the causes of which are not relevant to synchronous generators. Due to the differences in the requirements between these types of generation, PRC-024 is focused on equipment settings, and PRC-029 includes performance based requirements to “ride-through” events. Please refer to the technical rationale for additional information.	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation does not agree with creating a new IBR specific standard (PRC-29) to address the gaps in the Inverter-Based Resource. While Constellation recognizes that there has been some grid disturbance in the Odessa/California/Utah regions in the past couple years as a result of some IBRs not performing as intended, the creation of a new standard is a quick reaction without ensuring existing equipment's are capable to fully comply.	

Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The scope of PRC-029 is consistent with the SAR assigned to this team and the regulatory directives from FERC Order No. 901 that were assigned to this team. The need for a separate standard, PRC-029, is a consequence of both the different natures of synchronous and inverter-based generation and several recent events exhibiting significant IBR ride-through deficiencies and failures the causes of which are not relevant to synchronous generators. We cannot take the approach of PRC-024 for IBRs because there are too many other factors and causes of IBR ride-through failure not directly related to voltage and frequency protection settings that may, and have caused ride-through deficiencies and failures.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE supports creating a new standard to address Inverter-Based Resources (IBR) gaps identified. Texas RE is concerned, however, with the structure of the standard as it is presently proposed. As currently drafted, the proposed PRC-029-1 would wholly eliminate existing frequency and voltage protection setting verification requirements for IBR resources. Texas RE submits that this is contrary to FERC's intent in directing NERC to develop a comprehensive ride-through standard for IBR resources. FERC Order No. 901 explicitly directs NERC to draft a standard "that require[s] IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system excursions and that permit IBR tripping only to protect IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults." (Order No, 901, paragraph 190). FERC's intent behind the order was to expand the scope of applicable devices beyond protection system equipment subject to the current PRC-024 requirements to embrace a range of devices that can trip an IBR facility (inverters, plant controller, etc.). The ultimate goal is to better ensure that IBRs provide reliable performance during voltage and frequency excursions. Texas RE submits, however, that FERC did not intent to exclude IBR entities from the existing verification processes or significant limit the ability of the ERO to review protection system settings prior to an actual disturbance event. In its order, FERC specifically referenced the 2021 Odessa Disturbance Report jointly prepared by NERC and Texas RE staff ("2021 Odessa Disturbance Report"). The 2021 Odessa Disturbance Report in turn called for the development of a ride-through standard to replace PRC-024-3 because "the events analyzed by NERC regarding fault-induced	

reductions in solar PV output and wind output have identified issues with controls and protections unrelated to voltage and frequency." (2021 Odessa Report, at 29). While calling for a more comprehensive standard, however, the report simultaneously identified pervasive issues with protection system settings within the scope of the current PRC-024 standards. The report noted: "Numerous plant owner/operators have stated that they do not have sufficient technical staff on hand to interpret the results and will simply install what the consultant recommends. This is leading to poorly coordinated protection systems within the facility, causing unreliable performance from BPS-connected solar PV facilities in multiple interconnections." (2021 Odessa Report, at 17 (emphasis added)). In short, while acknowledging that the current PRC-024 standard is overly narrow, FERC and the various reports FERC references make clear that protection system verification failures remain an important contributing factor in the numerous disturbance events involving IBRs over the past few years.

As proposed, PRC-029-1 would result in a reliability gap by requiring that protection system settings no longer require verification. The Standard Drafting Team (SDT) explains in the draft PRC-029-1 Technical Rationale that "[a]n IBR becomes noncompliant with PRC-029 only when an event in the field occurs that shows that one or more requirements were not satisfied." Under the SDT's proposed approach, therefore, the existing PRC-024 protection system setting verification requirements would be eliminated and the sole mechanism to verify performance would be an IBR's failure to perform during a disturbance event. Texas RE posits that this approach is inconsistent with the intent of FERC's order to expand the applicable devices and settings that an IBR-entity must ensure are properly set to avoid unnecessary tripping during events. It is also inconsistent with findings that entities continue to experience issues properly setting (and verifying) existing protection systems within the scope of the current PRC-024 requirements.

Rather than pursue this approach, Texas RE suggests that the SDT consider retaining the existing protection system verification requirements as a foundational step, but augment those requirements with a general performance standard. Moreover, while Texas RE does not believe the SDT needs or should develop a comprehensive and prescriptive list of devices that must be appropriate set and coordinated to ensure IBR performance, the SDT should consider which measures and evidence would be appropriate for the GO and TO to demonstrate that its settings meet the various no-trip zone parameters described in Attachment 1. This should include sufficient evidence to show that protection system settings are properly set to not trip within appropriate no trip zones, as well as that other settings for inverters, plant controllers, and other devices are properly coordinated. Such clarity will ensure that at least minimum performance can be audited and verified prior to a disturbance event – the goal of the standards process.

Additionally, Texas RE noticed during the webinar, SDT stated that the requirements do not apply to individual IBR units. Requirement R1 seems to indicate that each IBR unit needs to remain electrically connected and continue to exchange current in accordance with the no-trip zones and operation regions.

Lastly, Texas RE recommends the SDT consider changing 'each IBR' to 'each IBR Facility' for all the Requirements.

Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The team agrees that the ability to validate the capability of each applicable IBR was not clear from the initial draft. Changes have been made to ensure the design/capability of each IBR can be validated prior to an event – in addition to retaining the event and performance-based requirements. The team does intend for each requirement to only apply at the plant/facility level; consistent with the disturbance monitoring equipment requirements within draft PRC-028. Also, the specific term identifying the applicable IBR facilities will have to await the completion of the IBR definition(s) by Project 2020-06. Changes have been made throughout the requirements and the applicability section to use only currently enforceable language.	
Joy Brake - Nova Scotia Power Inc. - NA - Not Applicable - NPCC	
Answer	No
Document Name	
Comment	
A performance standard should be based on function not technology type which is always changing. An IBR generation facility should meet the same performance threshold as traditional generation, with additional support devices as necessary incorporated into the facility design to meet the same level of performance as a traditional unit.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The need for a separate standard, PRC-029, is a consequence of both the different natures of synchronous and inverter-based generation and several recent events exhibiting significant IBR ride-through deficiencies and failures the causes of which are not relevant to synchronous generators. Due to the differences in the requirements between these types of generation, PRC-024 is focused on equipment settings, and PRC-029 includes performance based requirements to “ride-through” events. Please refer to the technical rationale for additional information.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	

Comment	
PRC-024-3 has not been in effect long enough to be deemed inadequate to address “gaps” and issues described in IBR disturbance reports. It became effective on 10/1/2022, which was long after major disturbances occurred, and as written, covers major causes of IBR disturbances such as voltage, frequency, and momentary cessation. Most importantly, the Standard clearly stated applicability to individual IBR units and it clearly stated no-trip zones. The Standard could have been modified to include and cover other recommendations from the disturbance report such as PLL protection and ramp rate mis-coordination.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The scope of PRC-029 is consistent with the SAR assigned to this team and the regulatory directives from FERC Order No. 901 that were assigned to this team. The need for a separate standard, PRC-029, is a consequence of both the different natures of synchronous and inverter-based generation and several recent events exhibiting significant IBR ride-through deficiencies and failures the causes of which are not relevant to synchronous generators. We cannot take the approach of PRC-024 for IBRs because there are too many other factors and causes of IBR ride-through failure not directly related to voltage and frequency protection settings that may, and have caused ride-through deficiencies and failures. Lastly, PRC-029 is plant/facility level based requirements and is not applicable at the individual inverter unit level.	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation does not agree with creating a new IBR specific standard (PRC-29) to address the gaps in the Inverter-Based Resource. While Constellation recognizes that there has been some grid disturbance in the Odessa/California/Utah regions in the past couple years as a result of some IBRs not performing as intended, the creation of a new standard is a quick reaction without ensuring existing equipment's are capable to fully comply. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The scope of PRC-029 is consistent with the SAR assigned to this team and the regulatory directives from FERC Order No. 901 that were assigned to this team. The need for a separate standard, PRC-029, is a consequence of both the different natures of synchronous and inverter-based generation and several recent events exhibiting significant IBR ride-through deficiencies and failures the causes of which are not relevant to synchronous generators. We cannot take the approach of PRC-024 for IBRs because there are too many other factors and causes of IBR ride-through failure not directly related to voltage and frequency protection settings that may, and have caused ride-through deficiencies and failures.	
Michael Goggin - Grid Strategies LLC - 5	
Answer	No
Document Name	
Comment	
A major concern with the separate Standards, as drafted, is that ride through performance is not required for synchronous generators under PRC-024-4, but it is for IBRs under PRC-029. PRC-02-4 simply requires protective relays to be set so they do not trip the generator within specified bounds, but it allows a resource to trip offline for other reasons. PRC-024-4 also allows a plant to trip if protection systems trip auxiliary plant equipment, per section 4.2.3. In contrast, PRC-029 requires IBRs to remain electrically connected and to continue to exchange current within the specified voltage and frequency bounds. Said another way, an IBR and a synchronous resource could both trip during the same disturbance, and the IBR would be in violation of PRC-029 but the synchronous generator would not be in violation of PRC-024-4, as long as the synchronous generator did not trip due to the settings of its protection system. To ensure grid reliability and resilience, all resources including IBRs and synchronous resources should ride through grid disturbances. The failure of synchronous generators to ride through grid disturbances threatens grid reliability as much or more than the failure of IBRs, as synchronous resources are often producing at a higher level of output, are more typically relied on as capacity resources, and often take longer to come back online and ramp up to full output if they trip due to a disturbance. FERC Order 901 directed NERC to treat IBR resources similarly to how NERC Standards treat synchronous generators, writing that the IBR Standard should “permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults.”{C}[1] Allowing synchronous generators to trip but requiring IBRs to ride through the same or similar disturbance could be challenged at FERC as undue discrimination.	

Not requiring ride-through performance from synchronous generators is also at odds with the intent for this project that NERC stated in its February 2023 comments on the FERC proposed rulemaking that led to Order 901: "A comprehensive, performance-based ride-through standard is needed to assure future grid reliability. To that end, NERC re-scoped an existing project, Project 2020-02 Modifications to PRC-024 (Generator Ride-through), to revise or replace current Reliability Standard PRC-024- 3 with a standard that will require ride-through performance from all generating resources."[2] FERC's Order 901 also noted NERC's statement that this project would require ride-through performance from all generating resources,[3] so a failure to require ride-through performance from synchronous generators may be contrary to both NERC and FERC's intent. The drafting team should make PRC-024-4 a ride-through performance requirement like PRC-029, or alternatively create a single standard that applies to both types of resources (with any necessary clarifications or minor differences in requirements to reflect the differences in IBR and synchronous generator technologies). {C}[1]{C} Order 901, https://www.ferc.gov/media/e-1-rm22-12-000, at paragraph 190 {C}[2]{C}https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Comments_IBR%20Standards%20NOPR.pdf, at 21-22 {C}[3]{C} Order 901, https://www.ferc.gov/media/e-1-rm22-12-000, at paragraph 185	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The team intends to continue evaluation of synchronous generators within the scope of the project. The team is seeking to meet regulatory timelines for IBR within FERC Order No. 901 and to address changes for IBR with the proposed PRC-029. Further, the team wants to assure that the physical differences between the technology types are fully represented in any new or modified requirements for synchronous machines and that such new or modified requirements are reasonable.	
Carey Salisbury - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
David Campbell - David Campbell On Behalf of: Natalie Johnson, Enel Green Power, 5; - David Campbell	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
While AEP agrees with creating PRC-029-1 to address the identified gaps, AEP recommends the SDTs for PRC-028, PRC-029 and PRC-030 review each proposed standard obligations to ensure there is a consistent, integrated plan across these projects and standards to achieve the goal of correcting the past performance of Invertor-Based Resources and IBR units. Having a coherent strategy document that explains how these three standards complement each other (and not be duplicative) would be beneficial.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

NERC will post updated information on the response to FERC Order No. 901. The three projects associated with Milestone 2 are meeting together to review draft changes at this time.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Synchronous generation and Inverter-based resources should have separate standards due to their unique differences. Presently, behavior of Synchronous generation during disturbances and faults is very well understood compared to IBR technology.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	IESO Comments for PRC-024 PRC-029 Draft 1.docx
Comment	
Complete set of comments for all Qs attached in file: IESO Comments for PRC-024 and PRC-029 Draft 1	
Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	
Response	
The team confirmed that these comments are included under other questions below and will be addressed there.	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	

Comment	
Yes, we need a separate a standard. The technologies are different enough that a separate standard will reduce confusion.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
AECI supports comments provided by the NAGF	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy supports the need for the new standard (PRC-029-1). In addition, FE supports EEI's comments which state:	

EEI agrees with most of the proposed language in Requirements R1, R2 and R6; however, the phrase “of an applicable IBR” should be removed. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant.

Additionally, Requirement R2, subpart 2.5 could be understood to mean that IBRs whenever the voltage at the high-side of the main power transformer is within the no-trip zone, as specified in Attachment 1, must not trip even if it might lead to equipment damage. We offer the following proposed edits in boldface to Requirement R2, subpart 2.5 to clarify the requirement. NERC Reliability Standards should never mandate that equipment run to failure.

2.5 **Each IBR shall only trip to prevent equipment damage, W**hen**ever** the voltage at the high-side of the main power transformer is within **of** the no-trip zone, as specified in Attachment 1, **each IBR shall continue to operate except when the continued operation of the IBR would lead to equipment damage**.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Terminology: The team has removed the word “applicable” and include a reference to the applicability section of the Standard. Any IBR that cannot meet voltage ride-through requirements, and may need to trip within the no-trip zone to protect equipment, would be covered under the documented equipment limitations as covered within Requirement R4 (previous R6).
R2.5: The team agrees with removing requirements on operation outside the no-trip zone and has removed R2.5.

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	Yes
Document Name	

Comment

Black Hills Corporation agrees that there is a gap in PRC-024-3 regarding performance of inverter-based resources (IBR). However, more consideration should be given to creating “protection-based” Standards for IBR, whether as an update to existing Standard PRC-024-3 or new Standard PRC-029-1 rather than the “event-based” approach currently being taken in PRC-029-1.

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT wants to avoid the complexities of OEM-specific IBR controls and protection by avoiding the protection settings issues altogether. We believe that a settings-based approach to the determination of compliance would become impractical if not impossible because of the varability of OEM designs. We cannot take the approach of PRC-024 for IBRs because there are too many other factors and causes of IBR ride-through failure not directly related to voltage and frequency protection settings that may, and have caused ride-through deficiencies and failures. A settings-based approach cannot practically address all factors and causes inherent to the various OEM designs of IBR units and plants. Some revisions were made to add clarity to capability-based requirements which require a demonstration of verified design/capability to ride-through.	
Stefanie Burke - Portland General Electric Co. - 6	
Answer	Yes
Document Name	
Comment	
PGE requests that the Standard Drafting Team (SDT) add clarity regarding Attachment A: Voltage Boundary Clarifications, Section: Evaluating Protection Settings, a. The most probable real and reactive loading conditions for the unit under study. Loading conditions vary depending on the type of unit, location, time of year, etc. How should an entity assess “most probable” loading conditions? Are entities being required to account for the worst case scenarios providing the greatest voltage change(s), not just a probable condition that may represent little to no significant voltage difference? PGE also notes that the Table References and Figure References are not aligned	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The attachment describes an approach to translating per unit voltage between the low and high sides of GSUs. This is something that needs to be done if voltage protection is applied at the generator terminal. It is only a recommendation. The protection setting no-trip zone references the POI voltage. The table and figure numbers in PRC-024-4 are now corrected.	
Colin Chilcoat - Invenergy LLC - 6	

Answer	Yes
Document Name	
Comment	
Yes, the technological differences warrant separate standards for IBRs and synchronous generation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	
Yes, the technological differences warrant separate standards for IBRs and synchronous generation.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Duke Energy recommends the implementation of EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	

Answer	Yes
Document Name	
Comment	
EEI supports the development of a new Reliability Standard to address gaps in Inverter-Based Resource Performance and while the SAR does not include any language that specifically addresses FERC Order No. 901, EEI has no concerns with the SDT adjusting PRC-029 in line with the directives contained in this Order.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Imane Mrini - Austin Energy - 6, Group Name Austin Energy	
Answer	Yes
Document Name	
Comment	
AE supports comments provided by Texas RE and the NAGF	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	

Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Maozhong Gong - GE - GE Wind - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
But we have additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see responses to the other comments below.	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
SRP believes that there is a huge lack of oversight in regard to inverter-based resources. Regulation on IBR controls is somewhat late but we are glad is happening.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Vistra agrees with AEP.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG supports IESO’s comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	

Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

Southern Company believes that separating synchronous machine facilities from IBR facilities simplifies the complication that would exist by addressing both types of facilities in the same standard. While the existing "legacy" facilities have demonstrated imperfect ride-through performance (reactions) during system initiated disturbances, Southern believes that the application of ride-through requirements should only be applicable to facilities designed, built, and commissioned after the development of such a standard. The existing "legacy" facilities were not designed or built to achieve the desired ride-through performance that is specified in PRC-029-1, requirements R1-R5 of this proposed standard, and should not be subject to those requirements. The demonstrated performance, while not matching the ideal performance dictated by this proposed standard, is not catastrophic to the interconnection. The notion that generator owners have not taken any actions to improve the reaction of the legacy facilities to system disturbances is false. Southern Company has reviewed and modified control and protection settings for inverter operations at multiple facilities since the issuance of the first two NERC Alerts on the Loss of Solar facilities and during the multiple disturbance analysis evaluations. Addressing the desired performance with new facilities which will have the component design and control strategies sufficient to meet the desired performance should be a measure adequate to address the frequency control, voltage control, and stability needs and concerns of the interconnection.

Perhaps a more reasonable approach towards achieving better IBR facility ride through performance during system disturbance events, is to require evaluations with every instance of a plant output hiccup. The proposed required evaluation process in PRC-030, requiring corrective action plans to minimize/eliminate/eradicate the reason for the hiccup, would address, where possible, action taken through control or protection system setting changes, or through hardware changes - for equipment placed in service after the effective date of this draft standard).

Southern would offer general concerns with synchronizing language across all draft standards. For example, M1 states: *"shall have evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements"*. This seems like an opportunity to clarify by explicitly referencing standard(s) addressing data collection. This example repeats in some form in each "M" paragraph. Should the evidence of actual recorded data in M1 and other measures synch up with the phased in approach to PRC-028?

Finally, Southern Company supports EEI and NAGF comments.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Scope of legacy IBR and approach by the team: The scope of PRC-029 is consistent with the SAR assigned to this team and the regulatory directives from FERC Order No. 901 that were assigned to this team. There is some potential for documented limitations within Requirement R6 and the Implementation Plan for legacy equipment that cannot meet any voltage ride-through requirements (R1 and R2). Some revisions were made to clarify design capabilities would still be required.
Coordination between PRC-029 and PRC-030 drafting teams: these team have implemented changes to those drafts that triggers within PRC-030 to initiate an analysis will be evaluated against PRC-029 ride through criteria. PRC-029 established the criteria and PRC-030 includes requirements for conducting the analysis of performance after a disturbance.
Performance Measures: The compliance measures for demonstration of performance were revised from "actual recorded data" to "actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data".

Richard Vendetti - NextEra Energy - 5

Answer	Yes
Document Name	

Comment

NextEra aligns with EEI's comments:

EEI supports the development of a new Reliability Standard to address gaps in Inverter-Based Resource Performance and while the SAR does not include any language that specifically addresses FERC Order No. 901, EEI has no concerns with the SDT adjusting PRC-029 in line with the directives contained in this Order.

Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
PG&E agrees with creating the new Standard PRC-029-1 to address IBRs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	

Answer	Yes
Document Name	
Comment	
See EEI comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Thank you for leaning heavily on IEEE 2800.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting	
Answer	Yes
Document Name	
Comment	
Yes, generator ride-through is an essential reliability service and the changing generation technology to inverter-based has led to the need for improved, applicable, appropriate, and technically accurate requirements that suit IBRs. However, it is critically important that the implementation of these requirements consider all stakeholder needs and capture important technical considerations so that the requirements sufficiently mitigate risks without causing unnecessary costs or burdens on any responsible entity.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Brytowski - Great River Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brittany Millard - Lincoln Electric System - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

George E Brown - Pattern Operators LP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shonda McCain - Omaha Public Power District - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katrina Lyons - Georgia System Operations Corporation - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Darcy O'Connell - California ISO - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Wesley Yeomans - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	2020-02_EPRI Comments on Draft NERC PRC-029 (IBR ride-through) Reliability Standard.pdf
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The team believes these comments have been sufficiently addressed through the response to other comments.	

2. Do you agree that the language within PRC-029-1 requirements R1, R2, and R6 regarding IBR plant-level performance during grid voltage disturbances is clear?	
Darcy O'Connell - California ISO - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee	
Answer	No
Document Name	
Comment	

The ISO/RTO Council (IRC) Standards Review Committee (SRC) recommends the following modifications to improve the clarity and better convey the intent of the standard.

Recommended changes to R1:

"…as specified in Attachment 1 except when needed to clear a fault or a documented **and communicated** equipment limitation exists in accordance with **Requirement R6."**

Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that each IBR remains electrically connected and continues to exchange current in accordance with the no-trip zones and operation regions as specified in Attachment 1 unless needed to clear a fault or a documented equipment limitation exists in accordance with Requirement R6.

Recommended changes to M1:

"…demonstrating adherence to ride-through requirements, as specified in Requirement R1**, or shall have evidence of a documented and communicated equipment limitation, as specified in Requirement R6**."

Recommended changes to R2:

"…each IBR's voltage performance adheres to the following, unless a documented **and communicated** equipment limitation exists…"

The SRC recommends that the SDT to review and align the data in **Attachment 1** to ensure that the data in Tables 1 and 2 aligns with what is shown in Figures 1 and 2. Currently, the graphs in Figures 1 and 2 do not match what is indicated in the Tables. For example, rows 1-3 in Tables 1 and 2 are identical, yet Figure 2 does not match Figure 1 by indicating a Voltage Ride-Through Requirement of 1.0.

It appears that the SDT's intent is to require continuous operation between 95% and 105% voltage with a minimum ride-through time of at least 1800 seconds (half an hour) when voltage is above 105% and not exceeding 110%. If the intent is actually that equipment must be able to operate *continuously* at voltages up to 110%, then the tables and plots should be labelled with a descriptor that clearly indicates that indefinite or continuous operation is required rather than operation for a minimum ride-through time (1800 seconds). For example, a version of Table 2 that achieves the SDT's apparent intent could look like the following:

Voltage (per unit)	**Minimum Ride-Through Time (sec)**
>1.2	N/A
<=1.2 and >1.1	1.0
<=1.1 and >1.05	1800
<=1.05 and >=0.95	Continuous
<0.95 and >=0.90	Continuous*

*current limitation permitted, with active or reactive power preference as specified

<0.90 and >=0.70	6
<0.70 and >=0.50	3
<0.50 and >=0.25	1.2
<0.25	0.32

While the above comments point out areas of ambiguity in the draft standard that need to be clarified, the SRC recommends that Table 1 and Table 2 be modified to require IBR plants remain connected indefinitely when the voltage is between 1.05 and 1.1 pu. The current draft standard requires units to remain online for 1800 seconds in this range, and the logic behind this threshold is not clear. The current PRC-024 standard requires units to remain on-line indefinitely for the above range. [*All SRC entities support the comments in this paragraph except MISO*].

In addition, the SRC recommends a part be added to the standard to directly address the Permissive Operating Region, similar to what is done in Part 2.1 (for the Continuous Operation Region) and Part 2.2 (for the Mandatory Operation Region) as, the rules surrounding the Permissive Operating Region are unclear if this is not addressed. For example, there should be some linkage between the body of the standard and Attachment 1, item 10. The SRC proposes the following language for consideration (new Part 2.3):

2.3 While voltage at the high-side of the main power transformer is within the Permissive Operation Region as specified in Attachment 1, an IBR may operate in current block mode only if necessary to protect the equipment. Otherwise, each IBR shall follow the requirements for the Mandatory Operation Region in Requirement R2, Part 2.2.

Recommended changes to R6:

The SRC is concerned that Requirement R6 as proposed provides an overly broad exemption, as the standard is silent as to what criteria must be met to qualify for an exemption and contains no requirement that a Corrective Action Plan be developed or that the equipment limitations be resolved or addressed. Only notification to other entities is required. The SRC recommends that the SDT:

- Develop more specific criteria as to what qualifies as an equipment limitation[1], OR A technical justification that addresses why corrective actions will not be applied nor implemented.
- Require exemptions be submitted to NERC and/or the Regional Entities for pre-approval in order to qualify for the exemption.

The SRC suggests there should be explicit requirements to both ‘document equipment limitations’ and to ‘communicate’ those documented limitations to the appropriate parties. The SRC proposes the following modifications to address this issue:

“Each Generator Owner and Transmission Owner with a **known** equipment limitation that would prevent an applicable IBR that is in-service by the effective date of this standard from meeting voltage ride-through requirements as detailed in Requirements R1 and R2 shall **document** each equipment limitation, develop a Corrective Action Plan to address the limitation, **and communicate both the limitation and the Corrective Action Plan** to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s).

Recommended changes to M6:

Each Generator Owner and Transmission Owner shall have evidence of **known** equipment Limitations accompanied by a Corrective Action Plan, as specified in Requirement R6, **having been** documented **and communicated** to each associated Planning Coordinator, Transmission Planner, and Reliability Coordinator prior to the effective date of PRC-029-1.

Each Generator Owner and Transmission Owner with changes to equipment shall have evidence of communication to each associated Planning Coordinator, Transmission Planner, and Reliability Coordinator.

[1] *See Implementation Plan (page 4), “only those IBR that are unable to meet voltage ride-through requirements due to their inability to modify their coordinated protection and control settings may be considered for potential exemption.” See Technical Rationale (page 9); i.e. specify which voltage band(s) and associated duration(s) cannot be satisfied or specific as to the number of cumulative voltage deviations within a ten-second time period that the equipment can ride-through if less than four… identify the specific equipment and explain the characteristic(s) of that equipment that prevent ride-through.*

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
R1 and R2: The team revised R1 and R2 to state "an equipment limitation in accordance with Requirement R6." R6 includes requirement language to document and communicate. Measure M4 (previous M6) was revised to include "known" as well as "and communicate" with the initial documentation of an equipment limitation.
Attachment 1: Tables and Figures in Attachment 1 have been revised to add clarity on the operation regions. The range of values in row #4 of Tables 1 and 2 to clarify the continuous operation region.
R2: The team added requirement subpart 2.3 to provide clarity on the operation within the Permissive Operation Region.
R4 (Previous R6): The team added clarity to Requirement R4 and the Implementation Plan to align the documentation and communication of known equipment limitations and exemptions with Requirement R3 of PRC-024-4.

Michael Brytowski - Great River Energy - 3

Answer	No
Document Name	Attachment 1 figures 1 and 2 .pdf

Comment

Comments: GRE requests the SDT review and align the data in **Attachment 1** so the data in Tables 1 and 2 aligns with what is shownin Figures 1 and 2. Currently, the graphs in Figures 1 and 2 do not match what is indicated in the Tables. (uploaded)

GRE recommends a part be added to the standard to directly address the Permissive Operating Region, similar to what is done in Part 2.1 (for Continuous Operation Region) and Part 2.2 (for Mandatory Operation Region) as, if left unaddressed, is unclear. For example, there should be some linkage between the body of the standard and Attachment 1, item 10. MRO NSRF proposes the following language for consideration (*new* Part 2.3):

2.3 While voltage at the high-side of the main power transformer is within the Permissive Operation Region as specified in Attachment 1, an IBR may operate in current block mode only if necessary to protect the equipment. Otherwise, each IBR shall follow the requirements for the Mandatory Operation Region in Requirement R2.2.

GRE is concerned that requirement R6 provides an overly broad exemption as written as the standard is silent as to what criteria must be met. Only notification to other reliability entities is required with no requirement to develop and implement a Corrective Action Plan. MRO NSRF recommends the SDT:

Develop more specific criteria as to what qualifies as an equipment limitation[1], OR Require exemptions be submitted to NERC and/or the Regional Entities for approval in order to qualify for the exemption. [1] *See Implementation Plan (page 4), i.e. "only those IBR that are unable to meet voltage ride-through requirements due to their inability to modify their coordinated protection and control settings may be considered for potential exemption." See Technical Rationale (page 9); i.e. specify which voltage band(s) and associated duration(s) cannot be satisfied or specific as to the number of cumulative voltage deviations within a ten-second time period that the equipment can ride-through if less than four… identify the specific equipment and explain the characteristic(s) of that equipment that prevent ride-through.* R2: GRE agrees with the present flexibility that some of the IBR VRT performance could be modified to meet the individual system needs by the applicable Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator. However, some clarity may be required on how this process is initiated and what type is evidence is required to demonstrate request is received and implemented. This may be an additional requirement assigned to the Transmission Planner. Each Transmission Planner, Planning Coordinator, and Transmission Operator that jointly specifies the following voltage ride-through performance requirements within their area(s) different than those specified under R2, shall make those requirements available to each associated applicable IBR Generator Owner and Transmission Owner.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Attachment 1:** Tables and Figures in Attachment 1 have been revised to add clarity on the operation regions. The range of values in row #4 of Tables 1 and 2 to clarify the continuous operation region. **R2:** The team added requirement subpart 2.3 to provide clarity on the operation within the Permissive Operation Region. **R4 (Previous R6)**: The team added clarity to Requirement R4 and the Implementation Plan to align the documentation and communication of known equipment limitations and exemptions with Requirement R3 of PRC-024-4.	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	No
Document Name	
Comment	

See comments below under question 4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
R2.5 & R5.1, et al. Each IBR shall only trip … "Trip" may be ambiguous. Does this mean disconnecting from the system to de-energize the IBR equipment, as in opening a circuit breaker? Or does it mean cease exchanging current? Or something else?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The team believes that "trip" is an industry term that is generally accepted when a plant/facility disconnects and electrically isolates itself. **R2:** The team agrees with removing requirements on operation outside the no-trip zone and has removed R2.5. **R5:** Requirement R5 has also been removed.	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
For R1, We recommend adding language to refer to plants that were previously exchanging current before the disturbance. For example, A BESS that is fully charged would be connected to the BES, but would not be exchanging current. For R2, change "each IBR's voltage performance" to	

voltage ride through performance. For R6, exemptions should not be automatically allowed. This would allow for bad designs relying on an exemption. Exemptions should only be for existing or legacy units. New units should not have the option for exemption.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Terminology**: That the requirement states "continues to exchange" implies that the facility was exchanging current prior to the disturbance. **R2:** R2 states that the voltage performance must meet the requirements within Attachment 1. Also, ride-through is not currently defined. **R4 (Previous R6):** R4 only applies for legacy units that have already documented known equipment limitations. Refer to the Implementation Plan for additional information.	
Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	No
Document Name	
Comment	
Southwest Power Pool joins the ISO/RTO Council Standards Review Committee comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to the ISO/RTO Council Standards Review Committee.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	

In the opinion of ACES, the newly proposed Glossary Terms are unnecessary and seemingly incongruous terms. For example, if the Mandatory Operating Region is required, should it not also be continuous? It is our opinion that these terms add little to no value and instead only create confusion where none was previously present. We recommend striking these new terms from the standard.

In ACES' opinion, R1 appears to be overly broad so as to require an applicable IBR to be operational at all times. This does not appear to allow for full facility outages without first having a "documented equipment limitation" per R6. Thus, as written, the GO will run the risk of non-compliance with either R1, R6, or both whenever a full facility outage of an IBR is required. Furthermore, it is unclear how R1 differs from R2 other than seeming to requiring the GO to ensure the GOP always keeps the unit online during to normal operation. We recommend striking R1 from the standard.

Additionally, we do not agree with the language of Requirement R2, Part 2.1.1. As written, R2 does not define what type of System disturbance is applicable and Part 2.1.1 requires the GO to continue producing active power at the pre-disturbance levels or its maximum capability; whichever is less. We have concerns with this approach. Namely, during an over frequency deviation event wherein the high side MPT voltage remains ≥ 0.9 p.u. and ≤ 1.1 p.u. In this instance, the frequency response algorithm within the IBR would attempt to reduce active power output. Due to the fast-acting nature of IBRs, it is likely that an IBR facility(ies) would respond to and correct such an event before a synchronous generating resource(s). However, in the aforementioned hypothetical example, to comply with R2.1.1, the IBR frequency response control would need to be either disabled or limited in its response to an over frequency System disturbance. In our opinion, this is not beneficial to the reliability of the BES. While possibly unlikely at the current time, this hypothetical scenario becomes increasingly likely as conventional synchronous generating resources are retired in favor of IBRs.

Furthermore, it is the opinion of ACES that R6 should be modified to include any potential regulatory limitations. This suggested approach is in line with the approach taken in PRC-024-4 R3. We recommend the modifying R6 as follows:

R6. Each Generator Owner and Transmission Owner shall document each known regulatory or equipment limitation that prevents an applicable IBR that is in-service by the effective date of this standard from meeting voltage or frequency ride-through requirements as detailed in Requirements R1 through R5.

6.1 Each Generator Owner and Transmission Owner shall include in its documentation:

6.1.1 Identifying information of the IBR (name, facility #, other)

6.1.2 Which aspects of voltage ride-through requirements that the IBR would be unable to meet

6.1.3 Identify the specific piece(s) of equipment causing the limitation.

6.2 The Generator Owner and Transmission 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, and Reliability Coordinator within 30 calendar days of any of the following:

6.2.1 Identification of a regulatory or equipment limitation.

6.2.2 Repair of the equipment causing the limitation that removes the limitation.

6.2.3 Replacement of the equipment causing the limitation with equipment that removes the limitation.

Lastly, the values specified in Table 1 and Table 2 in Attachment 1 do not align with the graphs shown in Figure 1 and Figure 2, respectively.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
Definitions: The team removed the terms for operating regions.
R1: Requirement R1 requires that the plant/facility must be electrically connected and exchanging current prior to the disturbance. R1 is needed to define clear boundaries for ride-through and R2 is needed to define performance for the different operation regions within the no-trip zone.
R1 and R2: The team used the defined term “voltage excursion” to align with language in PRC-024.
R2: The team added a footnote to 2.1.1 and other relevant footnotes to resolve the frequency excursion scenario.
R4 (Previous R6): The team included the *regulatory limitation* to align with PRC-024. R4 was also modied to clarify that changes to equipment that remedy the equipment limitation, that would remove the exemption.
Attachment 1: The tables and figures have been adjusted.

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	No
Document Name	

Comment

See comments submitted by Edison Electric Institute

Likes 0	

Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See EEI comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No

Document Name	
Comment	

Electric Reliability Council of Texas, Inc. (ERCOT) joins the comments of the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own in addition to the following comments, except to the extent of any specific differences between the SRC comments and the following comments from ERCOT.

As detailed below, the currently proposed language for Requirement R1 is not clear. Additionally, ERCOT believes that plant-level requirements are insufficient because individual IBR unit performance failures continue to occur and could, in aggregate, be just as impactful or more impactful than the complete loss of an IBR plant. The performance threshold should be coordinated with the threshold in PRC-030, and ERCOT believes a reasonable threshold would be the **lesser** of either 20% of the plant's gross nameplate rating, or 20 MW. In an IBR-dominated electric system, these aggregated losses could cause unreliable operations if not corrected. The past 8-10 years have demonstrated that IBR owners will not voluntarily correct these performance issues in the absence of a mandatory reliability standard.

SDT's proposed language (ERCOT finds the bold portions unclear):

"Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that **each IBR** remains electrically connected and continues to exchange current in accordance with the no-trip zones and operation regions as specified in Attachment 1 unless **needed** to clear a fault or a documented equipment limitation exists in accordance with Requirement R6."

ERCOT's proposed language:

"Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that each IBR, **and its IBR units**, remains electrically connected and continues to exchange current in accordance with the no-trip zones and operation regions as specified in Attachment 1 unless **the IBR, or its IBR units, needs to be tripped** to clear a fault or a documented equipment limitation exists in accordance with Requirement R6."

In addition to the concerns with Requirement R1 noted above, ERCOT is concerned that Requirement R2 does not clarify the timeframe encompassed by the term "System disturbance." Without further clarification, "System disturbance" may be interpreted to only describe the fault itself, even though control instability may manifest itself immediately after the fault clears or during the milliseconds or seconds after the fault clears, during which time frequency and voltage support are still critical. While IEEE 2800 defines the disturbance period, and there is an expectation that an IBR will perform acceptably in the continuous operation region, Requirement R2 is not clear that "riding-through" a disturbance includes both the fault and the non-fault portions of the disturbance along with the transition from ride-through mode to a new steady-state (i.e., the post-disturbance period). ERCOT suggests a 10-second window as a bright-line criterion.

SDT's proposed language for Requirement R2.

"R2. Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that during a System disturbance, each IBR's voltage performance adheres to the following, unless a documented equipment limitation exists in accordance with Requirement R6."

ERCOT's proposed language for Requirement R2:

"R2. Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that during, **and up to ten seconds after,** a System disturbance, each IBR's voltage performance **and its associated IBR units'** voltage performance adheres to the following, unless a documented equipment limitation exists in accordance with Requirement R6."

For Requirement R2, Part 2.2.2, ERCOT agrees that location-specific flexibility may be needed and defined by the TP, PC, RC, and or TOP; however, the language should clearly mandate that in such instances, the established performance requirements must also be met. Additionally, the current wording does not address the possibility that reactive current "response" could be in the wrong direction if not properly configured, and the language should be clarified to address this issue. ERCOT proposes the following language for Part 2.2.2 to capture the full spectrum of current priority modes from full aggressive reactive priority mode, to a de-tuned reactive response while in reactive priority mode, to an active priority mode.

"Adjust reactive current injection at the high-side of the main power transformer so that the magnitude of the reactive current **properly** responds to changes in voltage at the high-side of the main power transformer in accordance with default reactive prioritization **or as required by** any applicable Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator **that specifies** a certain magnitude **and timeliness** of reactive power response to voltage changes, **that specifies a maximum allowed active current reduction to provide reactive current, or that specifies** active power priority instead of reactive power priority."

ERCOT also recommends including the following language to help prevent unnecessary misoperations due to the use of unfiltered measurements or instantaneous (no time delay) settings for protection systems, consistent with NERC recommendations for addressing easily preventable performance failures.

R2.2.3 "Utilize sufficient time delays or filtering methods for any voltage measurements utilized by its protection equipment to prevent unnecessary trips due to calculation errors or transients."

ERCOT finds the bolded portions of the SDT's proposed language for Requirement R2, Part 2.3 to be unclear:

"The IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable Attachment 1 Table 1 or Table 2 no-trip zone voltage thresholds and time durations **in its response from** Mandatory or Permissive Operation Regions to the Continuous Operating Region."

ERCOT proposes the following language to clarify the issue:

"The IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable Attachment 1 Table 1 or Table 2 no-trip zone voltage thresholds and time durations **in its response as it transitions from** Mandatory or Permissive Operation Regions to the Continuous Operating Region."

ERCOT would also point out that the last clause may not be necessary because the IBR should not cause high voltage at any time, and the SDT could consider the following alternative language:

"The IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable Attachment 1 Table 1 or Table 2 no-trip zone voltage thresholds and time durations."

Consistent with the comments above on Requirement R2, Part 2.2.2, Requirement R2, Part 2.4 should be revised as follows to clarify that the other requirements or specifications from the RC/PC/TP/TOP must still be met:

"Each IBR shall restore active power output to the pre-disturbance or available level within 1.0 second when the voltage at the high-side of the main power transformer returns to the Continuous Operation Region from the Mandatory Operation Region or Permissive Operation Region (including operation in current block mode) as specified in Attachment 1, **or as required** by any applicable Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator **that specifies** a lower post-disturbance active power level requirement or **that specifies** a different post-disturbance active power restoration time."

Requirement R2, Part 2.5 may not be clear, in light of the new defined terms, that partial trips (including trips of individual IBR units) should not be allowed. While this topic should be coordinated with PRC-030, it goes to the heart of momentary cessation in that staying connected but not supporting frequency and voltage can, in aggregate, be just as detrimental to reliability as a full trip. The SDT should consider revising Part 2.5 to ensure that it is clear that there would be a violation at a particular level (e.g., the lesser of 20% of the unit's rated output, or 20 MW) of IBR unit trips. This could be graduated in severity level starting at the 20% or 20 MW level and increasing thereafter (e.g., 20%, 40%, 60%, 80%, and above).

ERCOT's proposed language for Part 2.5: "Each IBR, **or its IBR units,** shall only trip to prevent equipment damage, when the voltage at the high-side of the main power transformer is outside of the no-trip zone as specified in Attachment 1."

ERCOT also has concerns with the SDT's proposed Requirement R6 language:

"Each Generator Owner and Transmission Owner with **a documented equipment limitation** that would prevent an applicable IBR that is in-service by the effective date of this standard from meeting voltage ride-through requirements as detailed in Requirements R1 and R2 **shall communicate each equipment limitation to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s).**"

More specifically, the first bolded phrase ("a documented equipment limitation") appears to allow complete GO/TO discretion to declare a limitation with no process for review, approval, or acceptance of the limitation by any other entity. Only a communication to the PC, TP, and RC is required. It is unclear if the SDT's intention is that at some point these documented limitations would be reviewed or evaluated under the NERC CMEP (and it is unclear what standard the limitation documentation would be held to under such a review). At a minimum, Measure M6 and/or the Technical Rationale should provide more information about what an acceptable limitation might be and guidance for CMEP staff to use in evaluating the validity of limitations and the associated documentation.

The second bolded portion ("shall communicate each equipment limitation to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s)") is necessary, but may not be effective from a reliability perspective. A mere description of a limitation sent in an email or letter would not be useful for the PC/TP/RC but would meet the letter of Requirement R6. If the purpose of the communication is for PCs, TPs, and RCs to be able to assess the limitation and incorporate it into system studies, either Requirement R6 or the Technical Rationale should clarify that the communication needs to be in a format that is acceptable and useful to the PC/TP/RC (most likely in the form of an updated model that reflects the limitation). Additional burdensome administrative requirements to cover this communication process are not suggested, but at the very least the Technical Rationale should include guidance and set expectations to ensure that the communication will be useful to ensure the reliability of the grid. Additionally, ERCOT notes that FERC Order 901 recognized that "a subset of existing registered IBRs – typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements directed herein." ERCOT recommends that Requirement R6 be clarified to indicate that the equipment limitation process is only available to the limited subset of IBRs described in Order 901.

Additionally, ERCOT notes that Requirement R6, Part 6.2 does not require the TO/GO to actually improve ride-through capability even when equipment is replaced:

"Each Generator Owner and Transmission Owner with a previously communicated equipment limitation that repairs or replaces the equipment causing the limitation shall document and communicate such equipment changes to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s) within 30 days of the equipment change."

Rather than focusing on communication of changes, Part 6.2 should require the TO/GO to comply with all PRC-029 requirements and should not allow any documented limitations whenever equipment is changed or replaced; this approach would better align with FERC Order 901. PRC-029 should also include a requirement that mandates the implementation of software settings changes and upgrades (that do not require replacement of physical equipment) that improve ride-through capability. This is referenced in the implementation plan, but is absent from the actual requirements in PRC-029.

Equipment limitations may also not be currently captured in dynamic models, and the list of requirements should be updated to reflect this issue. The MOD standards may not accurately account for the provision of this information to all entities that perform studies (including stability limit and IROL determination studies that RCs perform); this would constitute a reliability gap. RCs and PC/TPs must be able to assess the impact of these exemptions to be able address the reliability impact under FERC Order 901.

Finally, ERCOT notes that FERC Order 901 requires NERC to "determine whether the new or modified Reliability Standards should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements. Any such exemption should be only for voltage ride-through performance for those existing IBRs that are unable to modify their coordinated protection and control settings to meet the requirements without physical modification of the IBRs' equipment." While it is clear that the SDT has determined that the standard should allow for documented exemptions for equipment limitations, the requirement language is unclear as to how or whether this exemption process is truly "limited" as required in Order 901, especially in light of the explicit reference to IBRs "that are *unable* to modify their coordinated protection and control settings to meet the requirements without physical modification of the IBRs' equipment." As ERCOT notes below, exemptions should be limited to scenarios where a responsible entity cannot otherwise achieve the necessary ride-through performance without physical equipment changes (inability to meet ride-through requirements that can be addressed simply by making software- or parameterization-type changes should not be grounds for an exemption) OR to scenarios where, even without making the remaining physical changes, the loss of a contingency would not cause instability, Cascading Outages, or uncontrolled separation that adversely impact the BPS.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
Evaluation of plant performance: The team is establishing plant/facility level ride-through requirements, consistent with the availability of disturbance monitoring data established within PRC-028. Further, Requirement R2 requires that the plant/facility must return to pre-disturbance values. Should the plant experience tripping of a portion of it's individual inverters, the overall plant would not be able to achieve compliance with R2. PRC-030 also include mechanisms for the entities with a wider-area view to request data, analyze performance, and establish corrective action plans.
Terminology used: The team has replaced the terms "disturbance" and "event" to use the type of excursion that is occurring. This change allows Requirement R1 to cover the time after a fault.
R2: The team agrees to some revised language in 2.2.2 to clarify the current response desired to improve performance.
R2.4 (Previous R2.3): The team clarified language in as suggested and added clarity on the voltage recovering as part of the change state.
R2.5 (Previous R2.4): Revisions included.
Previous R2.5: **R2:** The team agrees with removing requirements on operation outside the no-trip zone and has removed R2.5.
R4 (Previous R6): The team did add clarity to R4 and the implementation plan to specify what is allowable to an exemption that is consistent with the regulatory directives and assures adequate reliability can be evaluated.

Shonda McCain - Omaha Public Power District - 6

Answer	No

Document Name	
Comment	
OPPD supports comments provided by GRE: Michael Brytowski, Great River Energy, 3, 4/17/2024	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to Great River Energy.	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	No
Document Name	
Comment	
Requirement 1 and 2 These requirements mention that the IBRs should respond to the voltage changes with reactive current injection during a system disturbance, however, the magnitude of this response is not identified. The magnitude and expectation of the response should be clarified due to the fact that it can vary by unit and unit capabilities. Measures 1, 2, 3, 4, and 5 With regards to data recording, it is unclear what counts as recording? If the expectation is the same as contained in PRC-028-01 Draft 2, that should be specified; or otherwise identify alternate means of data recording. What if an entity does not have a recorded event to show compliance with the standard and prove its ability to ride through a system event?	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. **R1 and R2:** R2.2.2 allows for TP/PC/RC/TOP to require specific reactive current and active current magnitude as needed. The team does not intend to provide specificity of magnitude in R1 nor R2. **Measures:** The team specific language in the measures to tie disturbance monitoring data language to PRC-028-1. The team added specificity for demonstration of capability/design as well as performance. **Coordination between projects:** The team will work with the implementation plan to reflect the reality of the PRC-028 implementation.

Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
NextEra aligns with EEI's comments: EEI agrees with most of the proposed language in Requirements R1, R2 and R6; however, the phrase “of an applicable IBR” should be removed. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant. EEI also does not support Requirement R2, subpart 2.5 because it contains unneeded language, which adds confusion and implies that GOs can only trip outside of the trip zone if their equipment might become damaged. This has never been an obligation for synchronous generators, and we do not agree that this should be an obligation for IBRs. If NERC or the SDT believe that the no-trip zone needs to be expanded, they should justify such a change and present it for industry review and comment, otherwise, Requirement R2, subpart 2.5 should be deleted. And while we support Requirement R6 and the provisions to notify PCs, TPs and RC about equipment limitations that would prevent an applicable IBR from meeting ride-through requirements as detailed in Requirements R1 and R2, the Requirement does not go far enough because there may be technical reasons why an applicable IBR is unable to meet Requirement R3 through R5, as well. To address this concern, R6 should be expanded to include Requirement R1 through R5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	

Applicability: The team has removed the word “applicable” and include a reference to the applicability section of the Standard. Any IBR that cannot meet voltage ride-through requirements, and may need to trip within the no-trip zone to protect equipment, would be covered under the documented equipment limitations as covered within Requirement R4 (Previous R6).
R2: The team agrees with removing requirements on operation outside the no-trip zone and has removed R2.5.
R4 (Previous R6): The scope of allowable exemptions within R4 is consistent with the regulatory directives of Order No. 901. Requirements R3-R5 cannot apply.

Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

In regard to R1:

Does M1 imply that actual recorded data must be kept as evidence of ride-thru compliance for every in-scope IBR, for every system disturbance? Thesame question applies to R2-M2, R3-M3, R4-M4, and R5-M5.

The disturbance characteristic must be specified in order to trigger captures of performance information for every disturbance at every IBR facility - the characteristic which defines each type of disturbance must be defined in order to capture the record.

For each of the Measures M1 - M5, what "other evidence" can demonstrate compliance with R1-R5 other than recorded data?   How does the drafting team believe that generator owners can assure this performance expectation can be achieved prior to an actual event? There is no test verification that can be performed to confirm the expected performance. Consider providing some examples of what is acceptable as “other evidence”.

R1 mentions “operation regions specified in Attachment 1. R2, Part 2.1 mentions “continuous operation region as specified in Attachment 1” and Part 2.2 mentions “mandatory operation regions as specified in Attachment 1”. However, nowhere in attachment 1, is there mention of "continuous, mandatory, or permissive" operation regions.

In regard to R2:

For R2, Continuous Operation Region is not specified in Att. 1; it is merely a defined term in the draft standard.   Southern Company suggests that the referenced region be shown on the graph of Att.1, or that the words from the defined term simply be placed in the sub-requirement directly rather than creating a defined term.   The term region implies an area (volt-time). If the definition is simply specifying voltage level magnitude, simply state that. The definition labels are confusing; does permissive operation mean the IBR has permission to trip if the voltage is less than

0.1pu? It is observed that the values in the "mandatory operating region" match some of the borders of the "no trip zone" in Attachment 1, yet there is a time element that must be accounted for in determining if a trip is in compliance or not with the curve of Att. 1. For example, how can a long term (1-9 second) event where the voltage is 0.4pu be a Mandatory Operating Region? The voltage ride-thru curve does not specify this (for example).

Regarding the R2.2 and R2.3 requirement specifications, IBR facilities do not have per phase voltage regulation in their current designs, so the feasibility of successfully reacting to low system voltage (R2.2) with rapid reactive power injection while not possibly causing high voltage locally (R2.3) is questionable.

Regarding R2.1.1 & R2.1.2, it should also reference Interconnection Agreements (IA) limits since some IBR facilities have both solar and battery storage with an IA limit less than the aggregate sum.

Regarding R2.1.1 and R2.1.2, the idea that IBR Facility Power Plant Controllers operate to apparent power limits, is not in line with normal practices. Most PPC interfaces do not provide an apparent power reading or control function option. PPCs communicate separate MW and MVAR setpoints to all the of the site IBR Units and they follow or provide as capable the MWs and deliver MVARs up to the inverter reactive power limit.

Southern Company recommends changing wording to:

R2.1.1:Continue to deliver the predisturbance level of active power or available active power, whichever is less, and continue to deliver active powe r and reactive power up to its reactive power limit.

R2.1.2:If the IBR cannot deliver both active and reactive power due to a current or reactive power limit, when the applicable voltage is below 95% a nd still within the Continuous Operation Region, then preference shall be given to active or reactive power according to requirements specified by t he Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

R2.1.2 discusses giving preference to either active or reactive power based on requirements specified by transmission entities. There is some concern that this could be interpreted as a fluid preference that could require IBRs to actively configure active vs reactive capabilities.

Regarding R2.3, what happens if TOP has several lines down for maintenance in the area, which causes the part of the system the IBR facility is located, go from a strong system to a weak system?

R2.4 does not take into consideration other dynamic system conditions as a result of the fault and the effects on the PPC during a fault recovery. An example of this is Primary Frequency Response due to system frequency excursions during fault recovery. The active power recovery may be reduced or frozen during an underfrequency event while an IBR Resource is in recovery, thereby extending the time of the recovery.

R2 specifies performance for continuous and mandatory operation region, but not for permissive operation region. The performance during permissive operation region is in Attachment 1. Performance for all regions should be in Requirement R2.

Regarding R2.1.1, the first part, where IBR is required to continue to deliver the pre-disturbance level of active power or available active power, whichever is less is fine. However, the second part (and continue to deliver active power and reactive power up to its apparent power limit) is conflicting with the first part of this requirement. If the IBR plant's available active power was 50% of nameplate rating due availability of wind, solar irradiance, etc., then the second part of the requirement is stating that plant is required to produce reactive power to its apparent power limit given its available active power equal to 50% of nameplate rating. This is not correct.

In regard to R2.1, the clause 7.2.2.2 of the IEEE Std 2800 includes an exception when negative-sequence voltage is higher than certain threshold for a given time duration. Why the SDT not include this exception in the PRC-029?

In regard to R2.2, it appears the intent is to require that inject balanced current, during symmetrical faults, and unbalanced current during asymmetrical faults. However, the language is confusing. First, there is no plant level voltage regulation during a fault condition. Second, during unbalanced faults, what does a voltage regulation mean? One option is replace both Part 2.2.1 and Part 2.2.2 with following: The IBR shall inject current based on voltage deviation on high-side of main power transformer and as specified by the TP, PC, RC, or TOP.

In regard to R2.3,this requirement is confusing. Table 1 and 2 in Attachment 1 includes both low- and high-voltage thresholds. One meaning could be that the IBR shall not cause voltage to exceed LVRT threshold for a specified time duration. The true meaning is unclear. Is it correct that the intent is to focus on HVRT thresholds and time duration? The time duration for voltage > 1.2 per unit is not specified. Does this mean that IBR shall not cause overvoltage > 1.2 per unit whatsoever? If so, it needs to be written clearly.

In regard toR2.5, if there is no expectation for IBR to ride-through disturbance outside of no-trip zone, then there is no need for this requirement. For example, if voltage is zero for greater than specified time duration in Tables 1 and 2, say 1 second, then what is the point in staying connected and feeding into fault unless there is a risk of equipment damage? Additionally, there is no such expectation for frequency ride-through requirement R4.

R2.5 is not practical for the GO to determine where every individual piece of equipment would be damaged. There is no need to require tripping just before equipment damage if IEEE 2800 is guidance for equipment manufacturers.

In regard to Attachment 1:

1. There is no mention of continuous, mandatory, or permissive operation region in tables 1 and 2. Consider adding a column in tables 1 and 2 to show these operation regions.
2. For Table 1 and 2:
    - ≥1.20 should be >1.2

- ≥1.1 should be >1.1
- ≥1.05 should be >1.5

3. In IEEE Std 2800, the cumulative ride-through duration of 1800 second when voltage is > 1.05 is applicable to all nominal voltages except for 500kV nominal operating voltage. For 500kV nominal operating voltage, the equipment rated to 550kV (1.10 per unit) is available per ANSI C84.1. In IEEE Std 2800, see Note 1 under Table 12. Consider clarifying this in the PRC-029.
4. Note 7: A time window of 10-second is mentioned. However, when V>1.05, the ride-through duration is 1800 second, which is over a 3600-second time window in IEEE 2800.
5. Note 10: The purpose of current blocking in IEEE 2800 was not to protect the equipment but to rather to avoid tripping due to consequences of injecting current and hence, failure of ride-through.
6. Figures 1 & 2: why does the X-axis start at 0.1 second and not zero?

Finally, Southern Company supports EEI and NAGF comments.

Likes 0	
Dislikes 0	

Response

Thank you for your comments

Measures (events): The evidence of compliance for disturbance monitoring that are associated with voltage and frequency excursions that were System disturbances and would be identified for analysis or another trigger by an applicable entity within draft PRC-030. Evidence of disturbance monitoring of IBR associated with those disturbances would be triggered by compliance under the requirements for PRC-030.

Measures (data): The team agrees and the measures for R1 through R3 have been adjusted to include design/capability based requirements as well as the demonstration of performance during disturbances.

Attachment 1: The team agrees and has made changes to the tables and figures to include clear references to the operation regions. Explanation of the permissive operation region was added to Requirement 2. The definitions for the regions were also removed.

Exemptions: Voltage requirements R1 and R2 may have the capability for exemption of an known hardware-based limitation as detailed in the Implementation and Requirement R4 (Previous R6). The requirements include the flexibility for the IBR response based on the communication between the GO and the TP/PC.

R2 – use of reactive power: The team agrees that changes to clarify reaction power support in 2.1 was needed and made some adjustments to specify reactive power. This was broken into 2.1.1 and 2.1.2.

R2- -dynamic switching: Requirement 2.1.3 (previously 2.1.2) does not require dynamic switching between these two modes of operation. However, if that capability already exists, the operating mode would need to be specified by the TP, PC, RC, or TOP.

General operation expectations: IBR must adhere to ride through requirements and any direction as specified by their TOP(s) under any system operating condition.

R2 – clarification on frequency and voltage excursions: Requirement 2.5 (previously 2.4) now includes a footnote to add an exception for IBR response during a frequency excursion. Language was also changed to voltage/frequency excursions throughout to add clarity on this point. **Permissive Opertion Region:** The team added new 2.3 to include performance requirements during the permissive operation region. **R2 – use of reactive power**: Language was clarified in 2.1.1 and new 2.1.2 to address apparent vs reactive power limits per above. **General operation expectations**: Any additional operation for specific conditions such as the negative sequence overvoltage conditions, should be directed by the TOP as needed. **R2 General operation expectations**: Requirement 2.2. was clarified to allow for operating instructions from the TOP/PC/RC/TP to be followed but only if specified. Further usage of AVR was removed from the requirement. **R2 overvoltage clarification**: Revisions were made to R2.4 (previously 2.3) to specify exceedances above the high voltage thresholds. **R2.5:** The team has removed the previous 2.5. **Attachment 1 - corrections**: Attachment 1 tables and figures have been adjusted to correct some values and to include clear references to the operation regions. **Attachment 1 clarification on 500kv:** Attachment 1 sets the minimum expectation for operation regardless of voltage class. Expanding the no trip zone for 500kV may still be done based on the system need. **Attachment 1 clarification of accumulation Note**: The 10-second window is not used to define the thresholds within a particular operating region but it's the reset of the accumulation of the excursions into the mandatory and permissive operating regions. **Attachment 1 revision to Previous Note 10:** The team agrees on the details of note 10 in attachment 1 and have made this a new requirement in R2.3. **Attachment 1 - corrections**: The figures have been adjusted and now starts as zero.

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	No
Document Name	
Comment	
In 2.1.1 the "apparent power limit" is what is capable during the System disturbance correct? What is the "applicable voltage" to determine 95% in 2.1.2 (and why is per unit not used)? Where are the "requirements specified" by the TP/PC/RC/TOP and how does a GO or TO determine which one to use? If in the Planning world, the requirements should be specified in the TPL Standards. It is unclear what actions a TO/GO will take and be consistently applied. Since this is an event driven compliance review in the Operations Assessment time horizon, why would a TP or PC provide preference for active or reactive power in that timeframe? In a response study by the TP/PC, perhaps guidance on preference could be provided but it is unclear and NOT required in TPL Standards to this point. Clarity between the Tables and Figures in Attachment one needs provided to avoid confusion.	

Just to be clear, It appears that any new units after the effective date of this Standard have to meet all the criteria. Do the existing units with limitations have six months after the effective date of Standard to submit equipment limitations. With PRC-024-3 and PRC-024-2 already having a Requirement in place that requires limitations to be provided to the TP/PC and the industry already leaning on IRO-010 and TOP-003 for notifications, why is there a need to add an additional 6 months for Requirement R6? The RC already has communication capability with GOs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. **R2 – use of reactive power**: The team agrees and has clarified the language in 2.1. to use reactive power limit instead of “apparent power”. Also, the reference to “applicable voltage” was changed to “voltage”. The parent requirement states which voltage already. The team has also changed the 95% to per unit values to be consistent throughout the standard. **R2 – dynamic switching** The language of 2.1 and 2.2 was changed to clarify default preferences unless preference for active/reactive power support was established by the TP/PC/RC/TOP and based on system needs. Requirements do not require dynamic switching between these two modes of operation. A footnote was added that clarified that if a operation mode was specified by the TP/PC/RC/TOP, then that operation mode shall be followed instead. **Attachment 1 – corrections**: Attachment 1 tables and figures have been revised to clarify the operating regions and no-trip zones. **Implementation Plan**: The additional six month time frame is provided during the implementation plan for R4 (previous R6) to allow entities to verify documentation and cross check with the criteria within the new Standard. The required data to provide to qualify for an exemption must provide documentation stating which aspect of the voltage ride-through requirements cannot be met. Additionally, the criteria within PRC-029 is not one-to-one with criteria within PRC-024-4.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	

Comment

R1:

R1 should be revised to directly clarify, or include a footnote to clarify, the statement “that each IBR remains electrically connected and continues to exchange current” with “electrically connected, i.e., shall not trip, and continue to exchange current, i.e., shall not enter momentary cessation” that was provided in the Technical Rationale.

Attachment 1:

There is a discrepancy between the definition of the Term “Mandatory Operating Region” which states “≤ 1.2 per unit” and Table 1/Figure 1 or Table 2/Figure 2 which state “≥1.200” per unit “N/A”. Please clarify if Table 1/Figure 1 and Table 2/Figure 2 should state “>1200” or if the definition of the Term “Mandatory Operating Region” should state “<1.2 per unit”.

Please clarify Figure 1 and Figure 2 to clearly show the “Continuous Operating Region”, “Mandatory Operating Region”, and “Permissive Operating Region”, along with requirements beyond 10 seconds.

Please Clarify “9. The IBR may trip for more than four deviations of the applicable voltage….” In attachment 1.

R2.5:

This requirement is beyond the purpose of the standard, which is to establish Frequency and Voltage Ride-through Requirements for Inverter - Based Generating Resources and should be removed.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

R1: The team finds the current language of R1 does not need additional language and the TR provides the clarity. **Attachment 1:** The tables and figures in Attachment 1 have been updated for consistency. The continuous operating region applies for beyond 10 seconds. Note 9 in Attachment 1 is an exception of the overall requirement. **Requirement R2.5**: The team has removed R2.5.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
On behalf of the SERC Generator Working Group: R2.4 does not take into consideration other dynamic system conditions as a result of the fault and the effects they can have on the PPC during a fault recovery. An example of this is Primary Frequency Response due to system frequency excursions during fault recovery. The active power recovery may be reduced or frozen during an over-frequency event while an IBR Resource is in recovery, thereby extending the time of the full recovery. R2.5: It is not practical for the GO to determine where every individual piece of equipment would be damaged, nor should the GO be required to subject equipment to failure by trying to identify that point, run to it, and risk damaging it.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. **Requirement 2.5 (previously R2.4):** now includes a footnote to add an exception for IBR response during a frequency excursion. Language was also changed to voltage/frequency excursions throughout to add clarity on this point. **Previous Requirement 2.5**: has been removed.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	

OPG supports IESO's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to IESO.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
EEI agrees with most of the proposed language in Requirements R1, R2 and R6; however, the phrase "of an applicable IBR" should be removed. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant. EEI also does not support Requirement R2, subpart 2.5 because it contains unneeded language, which adds confusion and implies that GOs can only trip outside of the trip zone if their equipment might become damaged. This has never been an obligation for synchronous generators, and we do not agree that this should be an obligation for IBRs. If NERC or the SDT believe that the no-trip zone needs to be expanded, they should justify such a change and present it for industry review and comment, otherwise, Requirement R2, subpart 2.5 should be deleted. And while we support Requirement R6 and the provisions to notify PCs, TPs and RC about equipment limitations that would prevent an applicable IBR from meeting ride-through requirements as detailed in Requirements R1 and R2, the Requirement does not go far enough because there may be technical reasons why an applicable IBR is unable to meet Requirement R3 through R5, as well. To address this concern, R6 should be expanded to include Requirement R1 through R5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. **Terminolog**y: The team has removed the word "applicable" and include a reference to the applicability section of the Standard.	

Exemptions: Any IBR that cannot meet voltage ride-through requirements, and may need to trip within the no-trip zone to protect equipment, would be covered under the documented equipment limitations as covered within Requirement R4 (Previous R6).
R2.5: The team agrees with removing requirements on operation outside the no-trip zone and has removed R2.5.
Exemptions: The scope of allowable exemptions within Requirement R4 (Previous R6) is consistent with the regulatory directives of Order No. 901. Previous Requirements R3 and R5 have been removed.

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	No
Document Name	
Comment	
Vistra agrees with Invenergy	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to Invenergy.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	

Minnesota Power (MP) agrees with the MRO NSRF's comments on R1, R2, and R6, and the associated graphics from Attachment 1.

Additionally, MP notes that language from the Technical Rationale document specifies that R2.1, R2.3, and R2.4 are intended to apply when system conditions return to the Continuous Operation Region from the Mandatory or Permissive Operation regions. This should be specified in the standard.

Finally, MP proposes the following language changes to eliminate any possible uncertainty:

Section 2.1: "current or apparent power limit" to "current limit or apparent power limit"

Section 2.4: “pre-disturbance or available level” to “pre-disturbance level or available level, whichever is lesser”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment: **Attachment 1:** The tables and figures in Attachment 1 have been updated for consistency. The continuous operating region applies for beyond 10 seconds. Note 9 in Attachment 1 is an exception of the overall requirement. **R2 - clarity on language**: Language has been added to 2.4 (previously 2.3) to specify response as voltage recovers to the continuous operating region. **R2 – use of reactive power**: Language was clarified in 2.1.1 and new 2.1.2 to address apparent vs reactive power limits per above and other comments. **R2.5 (previous R2.4):** R2.4 was revised to include the language as suggested.	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation does not agree and feels the HVRT times are very high. Many wind turbines/inverters won't be able to meet those times, equipment in general and these systems have not been designed to withstand that much overvoltage. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The transient overvoltage requirement (previous R3) has been removed.	
Maozhong Gong - GE - GE Wind - NA - Not Applicable - NA - Not Applicable	
Answer	No

Document Name	
Comment	
For R6, R3,R4,R5 should be included as well for the documented limitation communication (see R6 comments below)	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The scope of allowable exemptions within R6 is consistent with the regulatory directives of Order No. 901. Previous requirement R3 and R5 have also been removed.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Imane Mrini - Austin Energy - 6, Group Name Austin Energy	
Answer	No
Document Name	
Comment	
AE supports comments provided by Texas RE and the NAGF	

Likes 0	
Dislikes 0	
Response	
Thank for your comment. See response to Texas RE and NAGF.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI agrees with most of the proposed language in Requirements R1, R2 and R6; however, the phrase "of an applicable IBR" should be removed. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant. EEI also does not support Requirement R2, subpart 2.5 because it contains unneeded language, which adds confusion and implies that GOs can only trip outside of the trip zone if their equipment might become damaged. This has never been an obligation for synchronous generators, and we do not agree that this should be an obligation for IBRs. If NERC or the SDT believe that the no-trip zone needs to be expanded, they should justify such a change and present it for industry review and comment, otherwise, Requirement R2, subpart 2.5 should be deleted. And while we support Requirement R6 and the provisions to notify PCs, TPs and RC about equipment limitations that would prevent an applicable IBR from meeting ride-through requirements as detailed in Requirements R1 and R2, the Requirement does not go far enough because there may be technical reasons why an applicable IBR is unable to meet Requirement R3 through R5, as well. To address this concern, R6 should be expanded to include Requirement R1 through R5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. **Terminology:** The team has removed the word "applicable" and include a reference to the applicability section of the Standard. Any IBR that cannot meet voltage ride-through requirements, and may need to trip within the no-trip zone to protect equipment, would be covered under the documented equipment limitations as covered within Requirement R4 (previous R6).	

Equipment protection: Any IBR that cannot meet voltage ride-through requirements, and may need to trip within the no-trip zone to protect equipment, would be covered under the documented equipment limitations as covered within Requirement R4.
Previous R2.5: The team agrees with removing requirements on operation outside the no-trip zone and has removed R2.5.
Excemptions: The scope of allowable exemptions within Requirement R4 Previous R6 is consistent with the regulatory directives of Order No. 901. Requirement R3 (Previous R4) cannot apply. Previous Requirement R3 and R5 has also been removed.
Previous R5: Previous Requirement R5 has been removed and added as an exemption to Requirement R1.

Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	

R1/R2: Recommend that Attachment 1 have a chart to include the Continuous Operation Region, Mandatory Operation Region, and Permissive Operation Region or have those regions specified on existing Voltage Ride -through Requirements Figure 1 and Figure 2.

Requests the SDT review and align the data in **Attachment 1** so the data in Tables 1 and 2 aligns with what is shown in Figures 1 and 2. Currently, the graphs in Figures 1 and 2 do not match what is indicated in the Tables.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment.
The tables and figures in Attachment 1 have been updated for consistency.

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy recommends the implementation of EEI and NAGF comments.

Duke Energy does not agree that the language is clear. The language seems close to but not completely in alignment with IEEE 2800-2022. It is not clear that the -029 requirements align with the IEEE 2800 requirements, especially given that most would want to comply with both. Many times the Continuous Operation Region is associated with the voltage regulation function and the Mandatory Operation Region is associated with LVRT. This separation is not maintained in various statements within 2.1 and 2.2. It is not clear how the plant or inverters can be configured to operate as specified in R2. Overall the language seems overly prescriptive and the DT may consider less specificity and possibly even a reference to IEEE 2800 rather than trying to restate it. Voltage regulation functions are typically based on POI voltage while LVRT functions are based on inverter terminal voltage. It is not clear that the requirements recognize this difference. Also, there are multiple references in R1 and R2 to Attachment 1 containing or representing the various Regions, but they are not graphically represented. The DT may consider revising the Att. 1 Figures (and moving the vertical axis crossing to 0.1 sec). tt seems the industry has often misinterpreted the area outside of the No-trip Zone as an area where the plant must trip. The DT may consider specifically addressing and emphasizing in the text and on the Figure that the plant is not required to trip in this area. For example, it may be labeled May Trip Zone. To that end, it would also be helpful for the GO to submit equipment ride through limits. That is the actual equipment limits, not the various voltage protection settings. With that information, plants would have the bases to provide the maximum ride-through beyond the No-Trip Zone and still not exceed plant main and BOP equipment limits.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. **Outside references:** Requirements within the NERC PRC-029 address the scope of the SAR and draw from IEEE2800 but are mandatory and enforceable requirements; in contrast to IEEE2800. NERC Standards cannot refer to outside sources for the purposes of requirement language, per the Rules of Procedure. **R2:** Language was clarified in 2.1.1 and new 2.1.2 to address apparent vs reactive power limits per above and other comments. **Attachment 1:** Figures and tables in attachment 1 have been updated to include the operation regions. The figures have been updated to cross at 0 seconds. The area outside of the no-trip zone is now labeled “may trip or may ride-through zone”.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	

WEC Energy Group does not agree that the language in R1, R2, and R6 is clear for the following reasons:

R1.:

WEC disagrees with text "… shall ensure that each IBR remains connected…". How else can an entity "ensure" to remain connected other than to set voltage protection outside the no-trip zone? The requirement must state what must be done. Based on Attachment 1, this is clearly voltage protection settings function so R1 should try and match PRC-024 R1. Otherwise, this requirement is open-ended as IBR could potentially be disconnected due to other reasons and the entity will be deemed non-compliant.

The "main power transformer" should be defined in a footnote, similar to what's proposed in PRC-028. It's unclear if main power transformer represents individual IBR step-up transformer or the site step-up transformer.

The phrase "exchange current" should be listed and defined in Terms section. Confusion exists in understanding if "exchange current" applies to BESS while charging, real/reactive current components, or something else. An exception should be added to exclude BESS from the PRC-029 requirements while charging.

WEC also disagrees with M1. The only means for an entity to "ensure IBR remains connected" is to set voltage protection and voltage ride-through protection according to Attachment 1. Making sure that the settings are applied should be the measure. The "recorded data" is an inconclusive statement. If the entity applied settings outside the no-trip zone and it still tripped, which could be for various other reasons, does that mean then entity is non-compliant? What needs to be recorded and where? Does this measure now mandate additional recording capabilities in addition to PRC-030? (Same comment applies to M2, M3, and M4).

R2.:

WEC disagrees with text "…. shall ensure that each IBR remains connected…". The requirement must state what TO and GO must do. Otherwise, this requirement is open-ended without a measurable statement.

2.1: Term "Continuous Operating Region" as defined conflicts with equipment design limitations. Power transformers may not be designed for continuous operations from 0.9 and 1.1 pu. Please refer to IEEE C57.12.00, sections 4.1.6.1, 4.1.6.2 and 5.5, and ANSI C84.1. Without some specific maximum time applied, the continuous operating region will conflict with equipment limitations. Due to this wide range, entities will simply take exception to R2 and R2 will not have any positive benefit for BES reliability. There is a reason PRC-024-3 has a 4 second limit. This limitation should clearly be introduced in PRC-029. Finally, the proposed "Continuous Operating Region" range conflicts with acceptable continuous operating ranges by Transmission Operators. Many Transmission Operators classify continuous operating range from 0.95 and 1.05 pu, and consider voltage ranges from 0.9 to 0.95 pu and 1.05 to 1.1 pu as abnormal voltage ranges.

2.1.2: There is nothing that governs a TP, PC, RC or TO to specify active/reactive power prioritization.

2.3: This requirement is inconclusive. The requirement must state what TO and GO must do. Otherwise, this requirement is open-ended without a measurable statement. Something regarding "IBR gain" was briefly mentioned during the PRC-029 webinar. A wide spectrum of gains and tuning parameters exist within the IBR controls. The requirement must state what parameters are to be addressed and how to set them. Gains and tuning parameters are covered in MOD-026 and MOD-027 standards and shall not be introduced here. Another potential issue could be with AVR function within the power plant controller. AVR/PPC failure could potentially cause higher voltage outputs. AVR failure, or any equipment failure, should not be the criteria to violate the standard. WEC recommends this requirement be removed.

2.4: WEC owns and operates multiple IBR sites and it is in our experience that the limitation to the 1 second requirement will come from the power plant controller. The ramp rate capabilities of the power plant controllers are far slower than inverter ramp rates and are typically in minutes range. WEC also had an instance where the power plant controller ramp rate increase was denied by the Transmission Operator/Planner.

2.5: This requirement contradicts the meaning of established No-Trip zone. If the No-Trip zone is inadequate, then SDT should evaluate and adjust it accordingly. In addition, having protection settings applied right at the equipment damage curve is not a standard protection practice, especially if events such as voltage excursions have a cumulative effect on insulation degradation that could lead to premature failures. WEC recommends this requirement be removed.

R6.: This requirement should include and cover equipment limitations associated with R3, R4, and R5.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
Performance and capability: Assigned regulatory directives from Order 901 to this team necessitate the inclusion of performance-based requirements that an entity would be required to demonstrate using actual measured data. Additional language has been added to require entities to demonstrate their capability to meet the requirements; including the protection and controller settings. Additional clarity on what recorded data has been included in the measures to align with new disturbance monitoring data requirements in PRC-028. There are many causes of ride-through failure beyond just over- and undervoltage protection settings that are encompassed within PRC-029.
MPT: The team has added a footnote as suggested.
Terminology: BESS are applicable to ride-through if they are electrically connected at the time of a fault. The phrase "continue to exchange current" is consistent if a BESS is charging prior to a fault and providing voltage support after the fault. However, the team agrees that a definition for Ride-through is preferable and has replaced usage of "continue to exchange current".

R2: R2 wording is consistent with expectations for performance-based requirements and how a GO or TO plant/facilities must performance during a voltage excursion.
Attachment 1: Tables and Figures in Attachment 1 have been revised to add clarity on the operation regions. The range of values in row #4 of Tables 1 and 2 to clarify the continuous operation region. Language has been added to R2 to clarify that if such specification has provided to the GO/TO that the GO/TO shall follow those specifications.
Measurement: PRC-029 is not an equipment setting standard. Both the SAR and the assigned Order 901 direct the team to include capability and performance-based requirements for ride-through. The criteria does not cover any equipment failure during a disturbance.
R2.5 (previously 2.4): R2.5 requires that a GO/TO follow any RC/PC/TOP/TP specified operation in response to a voltage excursion, including a specified ramping time. For legacy equipment, R6 covers any known regulatory or hardware-based limation.
Previous Requirement R2.5 has been removed.
Exemptions: The scope of allowable exemptions within R4 (previously R6) is consistent with the regulatory directives of Order No. 901. Frequency or phase-jump requirements cannot apply for exemption. New IBR cannot apply for exemption. This is consistent with the ordered directives.
Previous R3: Previous requirement R3 has been removed.
Previous R5: Previous Requirement R5 has been removed and added as an exemption to Requirement R1.

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

The NAGF provides the following comments:

a. Requirement R1 - the NAGF request clarification on the term "exchange" being used in the proposed language for Requirement R1.

b. Requirement R2 – the Terms section identified the terms: Continuous Operating Region, Mandatory Operating Region, and Permissive Operating Region but these terms are not specifically referenced in the tables for Attachment 1. The NAGF believes that the regions should be included in Attachment 1 for clarity.

c. The PRC-029-1 draft remains silent on the network condition, so it is unclear how to model the transmission system to test compliance with these requirements. One option is to assume that the transmission grid at the point of interconnection may be modeled as an ideal voltage source. Another option is to model the transmission grid as a voltage with a Thevenin impedance based on a short circuit ratio (minimum and maximum), which would consider the network condition at the point of interconnection. The NAGF requests clarity on this topic regarding testing compliance.

d. The requirement stated in R2.4 for IBRs to restore active power to the pre-disturbance or available level within 1.0 second when voltage at high-side of the main power transformer returns to Continuous Operation Region. Based on the TO studies or requirements, it is recommended that flexibility be allowed in the recovery time requirement. For example, if studies indicate that a slower ramp-rate and/or pause in the power ramp-up is beneficial then that should be allowed. The NAGF also recommends an active power recovery threshold of 90% of pre-disturbance level to account for measurement and IBR unit control uncertainties and tolerances.

e. The requirement stated in R2.1.1 must allow IBRs apparent power to be limited if the voltage is outside the normal operating range and the IBR units have reached their maximum current limit.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
Terminology: The phrase "continue to exchange current" is consistent if a BESS is charging prior to a fault and providing voltage support after the fault. However, the team agrees that a definition for Ride-through is preferable and has replaced usage of "continue to exchange current".
Attachment 1: Tables and Figures in Attachment 1 have been revised to add clarity on the operation regions. The range of values in row #4 of Tables 1 and 2 to clarify the continuous operation region.
Testing Conditions: The drafting team declines to address testing system conditions used to evaluate capability.
R2.5 (previous R2.4): R2.5 requires that a GO/TO follow any RC/PC/TOP/TP specified operation in response to a voltage excursion, including a specified ramping time. For legacy equipment, R6 covers any known regulatory or hardware-based limation.
R2 – use of reactive power: The team agrees that changes to clarify reaction power support in 2.1 was needed and made some adjustments to specify reactive power. This was broken into 2.1.1 and 2.1.2.
R2- -dynamic switching: Requirement 2.1.3 (previously 2.1.2) does not require dynamic switching between these two modes of operation. However, if that capability already exists, the operating mode would need to be specified by the TP, PC, RC, or TOP.

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	No
Document Name	

Comment

AZPS supports the following comments that were submitted by EEI on behalf of its members:

EEI agrees with most of the proposed language in Requirements R1, R2 and R6; however, the phrase “of an applicable IBR” should be removed. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant. EEI also does not support Requirement R2, subpart 2.5 because it contains unneeded language, which adds confusion and implies that GOs can only trip outside of the trip zone if their equipment might become damaged. This has never been an obligation for synchronous generators, and we do not agree that this should be an obligation for IBRs. If NERC or the SDT believe that the no-trip zone needs to be expanded, they should justify such a change and present it for industry review and comment, otherwise, Requirement R2, subpart 2.5 should be deleted. And while we support Requirement R6 and the provisions to notify PCs, TPs and RC about equipment limitations that would prevent an applicable IBR from meeting ride-through requirements as detailed in Requirements R1 and R2, the Requirement does not go far enough because there may be technical reasons why an applicable IBR is unable to meet Requirement R3 through R5, as well. To address this concern, R6 should be expanded to include Requirement R1 through R5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. **Terminology:** The team has removed the word “applicable” and include a reference to the applicability section of the Standard. Any IBR that cannot meet voltage ride-through requirements, and may need to trip within the no-trip zone to protect equipment, would be covered under the documented equipment limitations as covered within Requirement R4 (previous R6). **Previous R2.5:** The team agrees with removing requirements on operation outside the no-trip zone and has removed R2.5. **Exemptions**: The scope of allowable exemptions within R4 (previously R6) is consistent with the regulatory directives of Order No. 901. Frequency or phase-jump requirements cannot apply for exemption. New IBR cannot apply for exemption. This is consistent with the ordered directives.	
Joy Brake - Nova Scotia Power Inc. - NA - Not Applicable - NPCC	
Answer	No
Document Name	
Comment	
Concerns are covered other commenters.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	No
Document Name	
Comment	
PNM agrees with the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
R2.1/2.2 This states that the TO is who decides whether Active or Reactive Power is prioritized when a limit is reached. IBR sites will curtail real power to meet the reactive power request from the controllers. R2.4 This section would depend on the ramp rate of the units, 1.0 seconds seems extreme M2	

Will the PC's be communicating in writing to the Generator Owner every time there is a disturbance with the request for this data. How long will the data need to be held?

R4

5 hz/second is not a reasonable rate

M4

Will the PC's be communicating in writing to the Generator Owner every time there is a disturbance with the request for this data. The retention period for data is not defined.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
R2 – use of reactive power: The team agrees that changes to clarify reaction power support in 2.1 was needed and made some adjustments to specify reactive power. This was broken into 2.1.1 and 2.1.2.
R2- -dynamic switching: Requirement 2.1.3 (previously 2.1.2) does not require dynamic switching between these two modes of operation. However, if that capability already exists, the operating mode would need to be specified by the TP, PC, RC, or TOP.
Requirement 2.5 (previously 2.4) requires the GO/TO to follow provided TP/PC/RC/TOP restoration time or active power recovery threshold requirements – if different than default values in the sub-requirement.
M2 and M4: Coordination between PRC-029 and PRC-030 drafting teams have implemented changes to those drafts that triggers within PRC-030 to initiate an analysis will be evaluated against PRC-029 ride through criteria. PRC-029 establishes the criteria and PRC-030 includes requirements for conducting the analysis of performance after a disturbance. Data retention for R2 will be aligned with data retention requirements within PRC-030.
R4: Please refer to other comment responses in Question 3 below.

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and North American Generator Forum (NAGF) on question 2

Likes 0	
Dislikes 0	

Response

Thank you for your comments. See response to EEI and NAGF.

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy supports EEI comments. In addition, Dominion Enetgy has the following comments:

R2, Section 2.1 refers to the Continuous Opera**tion** Region as specified in Attachment 1; however the definition of Continuous Opera**ting** Region at the beginning of the standard is only applicable to voltages, measured at the high-side of the MPT that are between 0.9 PU and 1.1 PU. Does this mean that the definition of Continuous Operation Region is different from Continuous Operating Region? Or is the intent the same as the definition at the front of the standard and the “tion” should be changed to “ting”? Please clarify. This disconnect also exists in R2 and in R2.2.

R2, Section 2.1.2 and R2.4 both allude to a requirement for either the Transmission Planner, Planning Coordinator, Reliability Coordinator or Transmission Operator to provide a preference of active or reactive power if an IBR cannot deliver both due to a current or apparent power limit. The standard is not applicable to any of these listed entities and thus puts an administrative burden on the Generator Owner to contact each to determine a preference. Four entities determining the preference is three too many. A new requirement should be written directing one of the four entities to be the lead point of contact for the GO. Additionally, the standard should specify that the lead entity charged with determining the preference of active of reactive power should communicate the preference a minimum of 6 months prior to the effective date for the GO. The GO cannot put controls in place and ensure compliance until the TP, PC, RC or TOP has documented the compliance requirement.

R6, Section 6.2 is confusing since the Technical Rationale and FERC Order 901 Directives, Paragraph 193 states that “when the existing equipment is replaced, the exemption would no longer apply, and the new equipment must comply with the appropriate IBR performance requirements”. Further, FAC-002-5 considers replacement of inverters / converters or Power Plant Controllers to be “qualified changes” and would require a study

before implementation. This section seems to be an unnecessary administrative step, since the FAC-002 process would require submittal of "as-built settings" for the qualified change study.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Attachment 1:** The definitions for the operation regions have been removed. Additionally, the tables and figures in Attachment 1 have been updated for consistency. Also the continuous operation region have been labeled within the tables and figures. **Requirement R2:** R2 subparts require the GO/TO to follow provided TP/PC/RC/TOP restoration time or active power recovery threshold requirements – if different than default values in the sub-requirement. R2 does not intend that values other than the default values must be specified, only that performance for the plant/facility will be evaluated in accordance with those values if provided. Language has been added to M2 to clarify what evidence is expected if the TP/PC/RC/TOP provide other performance requirements. **Limitations:** Language has been added in R4 (previously R6) has been clarified that such a replacement would remove the limitation; consistent with the FERC Order 901. This is retained in PRC-029 to be consistent with new performance based requirements established in PRC-029 and the Order.	
George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports GRE's comments for this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	

Comment	
Constellation does not agree and feels the HVRT times are very high. Many wind turbines/inverters won't be able to meet those times, equipment in general and these systems have not been designed to withstand that much overvoltage. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The transient overvoltage requirement, R3, has been removed. Any qualifying R1 or R2 limitation is covered within R4 (previously R6).	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
1 The language "continues to exchange current" in R1 is not clear, please explain. 2 OEMs have not been forthcoming with operating limit data/equipment trip capabilities. Due to the lack of information from OEMs, we are concerned that the following language in R2.5 will be difficult to comply with: "Each IBR shall only trip *to prevent equipment damage*, when the voltage at the high-side of the main power transformer is outside of the no-trip zone as specified in Attachment 1". 3 The SDT should consider equipment where the manufacturer is not able to provide the limits where equipment damage can occur. For legacy equipment, this information may not be available or may be available at a very high cost to the GO. These scenarios should be included as limitations. 4· Charts in Attachment 1 should be updated to graphically show the performance regions	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. **Terminology:** The phrase "continue to exchange current" is consistent if a BESS is charging prior to a fault and providing voltage support after the fault. However, the team agrees that a definition for Ride-through is preferable and has replaced usage of "continue to exchange current". **R2.5:** The team agrees with removing requirements on operation outside the no-trip zone and has removed R2.5. **R2.5:** The team agrees with removing requirements on setting limits operation outside the no-trip zone and has removed R2.5. **Attachment 1:** Tables and Figures in Attachment 1 have been revised to add clarity on the operation regions. The range of values in row #4 of Tables 1 and 2 to clarify the continuous operation region.	
Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	
No, Invenergy disagrees that the language within PRC-029-1 requirements R1, R2, and R6 is clear. Specifically, we offer the below comments regarding these requirements: **R2.1.1.**: As currently drafted, R2.1.1. seems to ignore the changes to apparent power limits that could occur during a System disturbance. We recommended the following language: "R2.1.1. Continue to deliver the pre-disturbance level of active power or available active power, whichever is less, and continue to deliver active power and reactive power up to *the total aggregated current rating of the IBR Units in the plant*." **R2.1.2.**: Invenergy is concerned that the language in R2.1.2. regarding the active power or reactive power preferences of TPs, PCs, RCs, or TOPs may lead to increased confusion and unintended consequences. In its place, we recommend adopting something similar to the p/q/v capability curve demonstrated in Figure 8 of IEEE 2800-2022. **R2.3.**: It is unclear to us what R2.3. is requiring. Please clarify or remove. **R2.4.**: The ramp rate should be based on System needs; in weaker grid conditions such rapid ramping of active power could lead to power-oscillations or small-signal instability.	

R2.5.: This requirement is not auditable and is beyond the scope of the standard, which is to establish certain minimum ride-through requirements. As written, R2.5. suggests GOs should push their equipment as near to its breaking point as possible, even after the minimum ride-through requirements have been met. Thus, we ask R2.5. and similar statements throughout the draft standard be removed.

R6.: Given the technical limitations of many legacy IBRs, R6 must be thoroughly amended to allow exemptions for limitations related to frequency, rate-of-change-of-frequency, and phase angle change ride-through requirements. Consider that there are a range of possible concerns with legacy equipment and equipment already in commercial operation. At one end of the spectrum there exists legacy equipment where the manufacturer is no longer in business, or no longer produces the given IBR unit technology. In these cases, it is often infeasible to either truly document all aspects of the equipment limitations or to attempt to make any software or hardware modifications. At the other end of the spectrum there exists equipment that has been installed in recent years where software modifications may be enough to bring the units into compliance with the proposed requirements, after proper due-diligence and analyses have been performed. In between these two ends of the spectrum there is a range of possibilities.

Where available, software-only modifications are the most likely to yield meaningful reliability improvements where they are most needed while being technically and financially feasible for legacy IBRs to deploy. Indeed, the vast majority of performance issues identified with solar PV resources involved in the 2021 and 2022 Odessa disturbances (and other solar PV resources with the same inverter make/model that were not involved in the Odessa events) are being addressed in ERCOT with software-based modifications (see https://www.ercot.com/files/docs/2024/03/06/Odessa%20Update_03082024.pptx).

Thus, R6 needs a thorough rewrite to give due consideration, and acknowledgement, to these various nuances. Invenergy proposes the below modifications:

R6. Each Generator Owner and Transmission Owner with an applicable IBR that is in commercial operation prior to the effective date of this standard that is unable to meet the ride-through performance requirements detailed in Requirements R1 through R5 shall document the limitation, communicate each equipment limitation to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s), and provide a plan for making reasonable software and settings modifications that reduce or remove the limitation, if available and feasible.

6.1. Each Generator Owner and Transmission Owner shall include in its documentation, in each case as is available or can be reasonably obtained:

6.1.1. Identifying information of the IBR (name, facility #, other)

6.1.2. Current ride-through capability

6.1.3. Known ride-through limitations and documentation of such limitations

6.1.4. Reasonable software and settings modifications

6.1.5. Expected post-modification ride-through capability and documentation of any expected remaining limitations following implementation of such modifications

6.1.6. A schedule for implementing the modifications

6.2. Each Generator Owner and Transmission Owner with a previously communicated equipment limitation that makes a modification that reduces or removes such limitation shall document and communicate such modification to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s) within 30 days of the modification.

To supplement the language regarding reasonable software and settings modifications, the following language could be added to the Technical Rationale: Reasonable software and settings modifications are any available technically feasible modifications involving only software, firmware, settings, or parameterization changes that do not require physical modification of the IBR equipment and are reasonably priced.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
R2.1.1: Language was clarified in 2.1.2 (previously 2.1.1) to address apparent vs reactive power limits per above and other comments.
R2.1.2: R2.1.3 (previously R2.1.2) has been clarified that the GO/TO shall follow provided TP/PC/RC/TOP requirements if those are provided. The team has clarified that the GO/TO shall follow provided TP/PC/RC/TOP requirements only if those are provided.
R2.3: Language has been added to 2.4 (previously 2.3) to specify response as voltage recovers to the continuous operation region.
R2.4: R2.5 (previously R2.4) does not intend that values other than the default values must be specified, only that performance for the plant/facility will be evaluated in accordance with those values if provided. Language has been added to M2 to clarify what evidence is expected if the TP/PC/RC/TOP provide other performance requirements.
R2.5: What was previously R2.5 has been removed.
R4 (previously R6): The scope of allowable exemptions within R4 is consistent with the regulatory directives of Order No. 901. Frequency or phase-jump requirements cannot apply for exemption. Software-limitation also cannot apply for exemption. This is consistent with the ordered directives.

David Jendras Sr - Ameren - Ameren Services - 1,3,6

Answer	No
Document Name	

Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	

No, Invenergy disagrees that the language within PRC-029-1 requirements R1, R2, and R6 is clear. Specifically, we offer the below comments regarding these requirements:

R2.1.1.: As currently drafted, R2.1.1. seems to ignore the changes to apparent power limits that could occur during a System disturbance. We recommended the following language:

"R2.1.1. Continue to deliver the pre-disturbance level of active power or available active power, whichever is less, and continue to deliver active power and reactive power up to *the total aggregated current rating of the IBR Units in the plant*."

R2.1.2.: Invenergy is concerned that the language in R2.1.2. regarding the active power or reactive power preferences of TPs, PCs, RCs, or TOPs may lead to increased confusion and unintended consequences. In its place, we recommend adopting something similar to the p/q/v capability curve demonstrated in Figure 8 of IEEE 2800-2022.

R2.3.: It is unclear to us what R2.3. is requiring. Please clarify or remove.

R2.4.: The ramp rate should be based on System needs; in weaker grid conditions such rapid ramping of active power could lead to power-oscillations or small-signal instability.

R2.5.: This requirement is not auditable and is beyond the scope of the standard, which is to establish certain minimum ride-through requirements. As written, R2.5. suggests GOs should push their equipment as near to its breaking point as possible, even after the minimum ride-through requirements have been met. Thus, we ask R2.5. and similar statements throughout the draft standard be removed.

R6.: Given the technical limitations of many legacy IBRs, R6 must be thoroughly amended to allow exemptions for limitations related to frequency, rate-of-change-of-frequency, and phase angle change ride-through requirements. Consider that there are a range of possible concerns with legacy equipment and equipment already in commercial operation. At one end of the spectrum there exists legacy equipment where the manufacturer is no longer in business, or no longer produces the given IBR unit technology. In these cases, it is often infeasible to either truly document all aspects of the equipment limitations or to attempt to make any software or hardware modifications. At the other end of the spectrum there exists equipment that has been installed in recent years where software modifications may be enough to bring the units into compliance with the proposed requirements, after proper due-diligence and analyses have been performed. In between these two ends of the spectrum there is a range of possibilities.

Where available, software-only modifications are the most likely to yield meaningful reliability improvements where they are most needed while being technically and financially feasible for legacy IBRs to deploy. Indeed, the vast majority of performance issues identified with solar PV resources involved in the 2021 and 2022 Odessa disturbances (and other solar PV resources with the same inverter make/model that were not involved in the Odessa events) are being addressed in ERCOT with software-based modifications (see https://www.ercot.com/files/docs/2024/03/06/Odessa%20Update_03082024.pptx).

Thus, R6 needs a thorough rewrite to give due consideration, and acknowledgement, to these various nuances. Invenergy proposes the below modifications:

R6. Each Generator Owner and Transmission Owner with an applicable IBR that is in commercial operation prior to the effective date of this standard that is unable to meet the ride-through performance requirements detailed in Requirements R1 through R5 shall document the limitation, communicate each equipment limitation to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s), and provide a plan for making reasonable software and settings modifications that reduce or remove the limitation, if available and feasible.

6.1. Each Generator Owner and Transmission Owner shall include in its documentation, in each case as is available or can be reasonably obtained:

6.1.1. Identifying information of the IBR (name, facility #, other)

6.1.2. Current ride-through capability

6.1.3. Known ride-through limitations and documentation of such limitations

6.1.4. Reasonable software and settings modifications

6.1.5. Expected post-modification ride-through capability and documentation of any expected remaining limitations following implementation of such modifications

6.1.6. A schedule for implementing the modifications

6.2. Each Generator Owner and Transmission Owner with a previously communicated equipment limitation that makes a modification that reduces or removes such limitation shall document and communicate such modification to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s) within 30 days of the modification.

To supplement the language regarding reasonable software and settings modifications, the following language could be added to the Technical Rationale: Reasonable software and settings modifications are any available technically feasible modifications involving only software, firmware, settings, or parameterization changes that do not require physical modification of the IBR equipment and are reasonably priced.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
R2.1.1: Language was clarified in 2.1.2 (previously 2.1.1) to address apparent vs reactive power limits per above and other comments.
R2.1.2: R2.1.3 (previously R2.1.2) has been clarified that the GO/TO shall follow provided TP/PC/RC/TOP requirements if those are provided. The team has clarified that the GO/TO shall follow provided TP/PC/RC/TOP requirements only if those are provided.
R2.3: Language has been added to 2.4 (previously 2.3) to specify response as voltage recovers to the continuous operation region.
R2.4: R2.5 (previously R2.4) does not intend that values other than the default values must be specified, only that performance for the plant/facility will be evaluated in accordance with those values if provided. Language has been added to M2 to clarify what evidence is expected if the TP/PC/RC/TOP provide other performance requirements.
R2.5: What was previously R2.5 has been removed.
R4 (previously R6): The scope of allowable exemptions within R5 is consistent with the regulatory directives of Order No. 901. Frequency or phase-jump requirements cannot apply for exemption. Software-limitation also cannot apply for exemption. This is consistent with the ordered directives.

Brittany Millard - Lincoln Electric System - 5

Answer	No
Document Name	

Comment	
A review of the data in Attachment 1 and Tables 1 and 2 should be performed so that they align. Currently, the graphs in Figures 1 and 2 do not match what is indicated in the Tables. We would recommend a part be added to the standard to directly address the Permissive Operating Region, similar to what is done in Part 2.1 (for Continuous Operation Region) and Part 2.2 (for Mandatory Operation Region) as, if left unaddressed, is unclear. For example, there should be some linkage between the body of the standard and Attachment 1, item 10. The following language is provided for consideration (*new* Part 2.3): **2.3** While voltage at the high-side of the main power transformer is within the Permissive Operation Region as specified in Attachment 1, an IBR may operate in current block mode only if necessary to protect the equipment. Otherwise, each IBR shall follow the requirements for the Mandatory Operation Region in Requirement R2.2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The tables and figures in Attachment 1 have been updated for consistency. The team agrees and has added a new requirement R2.3 for the permissive operation region.	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Plese review and align the data in Attachement 1 so that data in Tables 1 & 2 align with Figures 1 & 2. Also, it is recommended a part be added to the standard to directly address the Permissive Operating Region, similar to what is done in Part 2.1 (for Continuous Operation Region) and Part 2.2 (for Mandatory Operation Region) as, if left unaddressed, is unclear. For example, there should be some linkage between the body of the standard and Attachment 1, item 10. See the following proposed language for consideration (*new* Part 2.3):	

2.3 While voltage at the high-side of the main power transformer is within the Permissive Operation Region as specified in Attachment 1, an IBR may operate in current block mode only if necessary to protect the equipment. Otherwise, each IBR shall follow the requirements for the Mandatory Operation Region in Requirement R2.2.

OPTION A.

Requirement R6 provides an overly broad exemption as written as the standard is silent as to what criteria must be met. Only notification to other reliability entities is required with no requirement to develop and implement a Corrective Action Plan. The SDT should consider:

- Develop more specific criteria as to what qualifies as an equipment limitation[1], OR
- Require exemptions be submitted to NERC and/or the Regional Entities for approval in order to qualify for the exemption.

OPTION B.

Leave R6 as written, apply R6 to R1 through R5.

it is recommended that there be no requirement to document limitations on legacy equipment and that this standard focuses on equipment brought into service after the implementation date.

R2: We agree with the present flexibility that some of the IBR VRT performance could be modified to meet the individual system needs by the applicable Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator. However, some clarity may be required on how this process is initiated and what type is evidence is required to demonstrate request is received and implemented. This may be an additional requirement assigned to the Transmission Planner. Each Transmission Planner, Planning Coordinator, and Transmission Operator that jointly specifies the following voltage ride-through performance requirements within their area(s) different than those specified under R2, shall make those requirements available to each associated applicable IBR Generator Owner and Transmission Owner

[1] *See Implementation Plan (page 4), i.e. "only those IBR that are unable to meet voltage ride-through requirements due to their inability to modify their coordinated protection and control settings may be considered for potential exemption." See Technical Rationale (page 9); i.e. specify which voltage band(s) and associated duration(s) cannot be satisfied or specific as to the number of cumulative voltage deviations within a ten-second time period that the equipment can ride-through if less than four… identify the specific equipment and explain the characteristic(s) of that equipment that prevent ride-through.*

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. **Attachment 1:** Tables and Figures in Attachment 1 have been revised to add clarity on the operation regions. The range of values in row #4 of Tables 1 and 2 to clarify the continuous operation region. **R2.3 (permissive region):** The team agrees and has added a new requirement R2.3 for the permissive operation region. **R4 (previously R4):** The scope of allowable exemptions within R4 is consistent with the regulatory directives of Order No. 901. Frequency or phase-jump requirements cannot apply for exemption. New IBR cannot apply for exemption. This is consistent with the ordered directives. **Requirement R2** subparts require the GO/TO to follow provided TP/PC/RC/TOP restoration time or active power recovery threshold requirements – if different than default values in the sub-requirement. R2 does not intend that values other than the default values must be specified, only that performance for the plant/facility will be evaluated in accordance with those values if provided. Language has been added to M2 to clarify what evidence is expected if the TP/PC/RC/TOP provide other performance requirements.

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
We believe that language needs to be added to M1, similar to that provided in the other Measures, to specify the initiating event that triggers the requirement for R1 evidence of compliance.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Coordination between PRC-029 and PRC-030 drafting teams have implemented changes to those drafts that triggers within PRC-030 to initiate an analysis will be evaluated against PRC-029 ride through criteria. PRC-029 established the criteria and PRC-030 includes requirements for conducting the analysis of performance after a disturbance. The compliance measures were revised from “actual recorded data” to “actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data”. Additions were made to the requirements to require demonstration of IBR capability and the measures were updated to include capability-based evidence.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No

Document Name	
Comment	
Black Hills Corporation supports EEI's and NAGF's comments. Additionally, Black Hills Corporation has concerns regarding event-based "Measures" for Requirement R2, R3, R4 and R5 as GO will likely not have immediate knowledge of "System disturbance" or other transmission system events (transient overvoltage due to switching, frequency excursion, instantaneous positive sequence voltage phase angle changes) when they occur and data collection systems have a limited amount of storage capacity (i.e. data overwrite happens over time, in our case, data is retained for a rolling 12 months). If available data remains the "Measure" for demonstrating compliance, then consideration needs to be given to when and how GO are notified of an event, so data can be reviewed and archived for future demonstration of compliance.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI and NAGF. Coordination between PRC-029 and PRC-030 drafting teams have implemented changes to those drafts that triggers within PRC-030 to initiate an analysis will be evaluated against PRC-029 ride through criteria. PRC-029 established the criteria and PRC-030 includes requirements for conducting the analysis of performance after a disturbance. The compliance measures were revised from "actual recorded data" to "actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data".	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy finds 2.4 requesting the return to of the Active Power is restrictive and needs to be inclusive of Reactive Power due to voltage response.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Requirement 2.5 (previously 2.4) now includes a footnote to add an exception for IBR response during a frequency excursion. Language was also changed to voltage/frequency excursions throughout to add clarity on this point.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
AECI supports comments provided by the NAGF	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to NAGF.	
Brian Lindsey - Entergy - 1	
Answer	No
Document Name	
Comment	

- 2.1.2 refers to requirements specified by the TP, TOP, PC, RC. It is unclear what the expectation is if those requirements have not been defined.
- Is 2.2.2 is stating that the IBR shall maintain reactive power per default setpoints unless a new reactive setpoint has been requested or it's been requested to maintain a certain active power? Why wouldn't this be worded similarly to the sub-bullets in 2.1?
- 2.3: if the IBR is already responding to Mandatory or Permissive Operation regions (exceedances of Attachment 1 Table 1 or Table 2), how could it then cause an exceedance?
- R2.4   There is concern that the controls will be either unable to respond within the 1 second timeframe, or that the historical records to prove the response would not have the resolution to be meaningful.

- R 2.5: How would someone prove that an IBR tripped only to prevent equipment damage? This sub-bullet cannot be enforced.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
R2.1.2 (previous R2.1.1) and R2.1.3 (previous 2.1.2): Language was clarified in R2.1.2 and R2.1.3 to address apparent vs reactive power limits per above and other comments. R2.1.3 has been clarified that the GO/TO shall follow provided TP/PC/RC/TOP requirements if those are provided. Requirement R2 subparts require the GO/TO to follow provided TP/PC/RC/TOP restoration time or active power recovery threshold requirements – if different than default values in the sub-requirement. R2 does not intend that values other than the default values must be specified, only that performance for the plant/facility will be evaluated in accordance with those values if provided. Language has been added to M2 to clarify what evidence is expected if the TP/PC/RC/TOP provide other performance requirements.
R2.4 (previous R2.3) - recovery: Language has been added to R2.4 to specify response as voltage recovers to the continuous operating region.
1 second: Regarding the 1 second, R4 covers any known regulatory or hardware-based limitation for legacy equipment.
R2.5: The team agrees with removing requirements on operation outside the no-trip zone and has removed R2.5.

Helen Lainis - Independent Electricity System Operator - 2

Answer	No
Document Name	Proposed change to table Q2.PNG

Comment

The IESO recommends the following modifications to the text improve clarity or to better convey intent.

With regards to R1:

"…as specified in Attachment 1 unless **not doing so is** needed to clear a fault or a documented **and communicated** equipment limitation exists in accordance with **Requirement R6."**

With regards to M1:

"…demonstrating adherence to ride-through requirements, as specified in Requirement R1**, or shall have evidence of a documented and communicated equipment limitation, as specified in Requirement R6**."

With regards to R2:

"…each IBR's voltage performance adheres to the following, unless a documented **and communicated** equipment limitation exists…"

With regards to 2.1: (and Tables 1 & 2, Figures 1 & 2):

There appears to be inconsistency between the definition of 'Continuous Operation Region', the Minimum Ride-Through Time values stated in Tables 1 & 2, and the plots in Figures 1 & 2.

It seems the intent is to have 'continuous' operation between 95% and 105% voltage, and a minimum ride-through time of at least 1800 seconds (half an hour) when voltage is above 105% and not exceeding 110%. If it is really required that equipment must be able to operate ***continuously*** at voltages up to 110%, then the tables and plots should be labelled with a descriptor that implies indefinite operation is required (i.e., continuous) rather than a minimum time (1800 seconds). For example, a version of Table 2 that achieves what seems to be intent could look like the following:

See file attached - Proposed change to table Q2

With regards to 2.5:

The IESO believes the principle of tripping only when necessary (i.e., to clear faults and to prevent equipment damage during disturbances) is important enough that it warrants a dedicated requirement. With regards to tripping during over-voltages, this principle of only tripping for equipment protection purposes may apply equally to system disturbances discussed in R2 and to switching transients as discussed in R3 (tripping for equipment protection is not presently addressed in R3, though is acknowledged in the Technical Rationale document).

With regards to R6:

The IESO suggests there should be explicit requirements to both 'document equipment limitations' and to 'communicate' those documented limitations to the appropriate parties. The following modifications are proposed:

"Each Generator Owner and Transmission Owner with a **known** equipment limitation that would prevent an applicable IBR that is in-service by the effective date of this standard from meeting voltage ride-through requirements as detailed in Requirements R1 and R2 shall **document** each equipment limitation **and communicate it** to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s).

With regards to M6:

Each Generator Owner and Transmission Owner shall have evidence of **known** equipment limitations, as specified in Requirement R6, **having been** documented **and communicated** to each associated Planning Coordinator, Transmission Planner, and Reliability Coordinator prior to the effective date of PRC-029-1.

Each Generator Owner and Transmission Owner with changes to equipment shall have evidence of communication to each associated Planning Coordinator, Transmission Planner, and Reliability Coordinator.

Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	

Response

Thank you for your comment.
R1: Modifications have been made to R1 and M1 for clarity – please see the new draft for those changes.
Attachment 1: The tables and figures in Attachment 1 have been updated for consistency. The operation regions have been included on the figures.
R2: Previous requirement R2.5 has been removed.
R5: Previously R6 has been updated to include “known”, “regulatory”, and “communicated”.

Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power does not agree that the language in the applicability section of PRC-029-1 is clear. The applicable facilities language in Section 4 is vague and difficult for entities to understand what is in scope of the Standard. Specifically, the term "BPS IBR" is broad and would encompass all transmission connected IBRs, regardless of size or interconnection voltage. Additionally, the language and formatting of the applicability sections in PRC-028, PRC-029 and PRC-030 are not consistent. These three Standards apply to the same facilities, and therefore, should use the same language. Tacoma Power recommends that Section 4 of PRC-029 and PRC-030 should be revised to align with the language proposed in Section 4 of PRC-028, as follows:

4.1. Functional Entities:

4.1.1. Transmission Owner that owns equipment as identified in section 4.2

4.1.2. Generator Owner that owns equipment as identified in section 4.2

4.2. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.	
Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	
Thank you for your comments. The drafts for PRC-028, PRC-029, and PRC-030 have been updated for consistency. The Facilities sections between these drafts will stay aligned moving forward.	
Leah Gully - Madison Fields Solar Project, LLC - 5 - RF	
Answer	No
Document Name	
Comment	
See "additional comments" for details	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	2020-02_EPRI Comments on Draft NERC PRC-029 (IBR ride-through) Reliability Standard.pdf
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. The team believes these comments have been sufficiently addressed in other comment responses.	
Michael Goggin - Grid Strategies LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
David Campbell - David Campbell On Behalf of: Natalie Johnson, Enel Green Power, 5; - David Campbell	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Carey Salisbury - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you.	
Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting	
Answer	Yes
Document Name	
Comment	
Yes. The SDT should consider citing IEEE 2800-2022 directly in the standard and consider using the IEEE 2800-2022 ride-through requirements as a means to comply with Requirements R1-R5 instead of using Attachment 1 of the standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. NERC Standards cannot refer to outside sources for the purposes of requirement language, per the Rules of Procedure. From the NERC Rules of Procedure: "Reliability Standards shall be complete and self-contained. The Reliability Standards shall not depend on external information to determine the required level of performance."	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Remove from R1 "*and operation regions*" since this is already required in R2. Move R2.5 to a sub-requirement of R1, since R1 is the no-trip requirement not R2.	

R2.5 should read be rearranged to be more clear, "When the voltage at the high-side of the main power transformer is outside of the no-trip zone as specified in Attachment 1, each IBR shall only trip to prevent equipment damage."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Terminology**: The team agrees and has defined a new term for Ride-through and replaced language in the requirements with this new term. Attachments have also been updated to utilize this term as the "Must Ride-through Zone". **R2.5:** The team agrees with removing requirements on operation outside the Must Ride-through Zone and has removed R2.5.	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
SRP believes the language in R1 and R2 provides clear expectations of how IBR controls should behave during short circuit events.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	

While the language is clear, the SDT explains in the draft PRC-029-1 Technical Rationale that "An IBR becomes noncompliant with PRC-029 only when an event in the field occurs that shows that one or more requirements were not satisfied." See Question 4 comment for RF's concerns with this approach.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Measures (data)**: The team agrees and the measures for R1 through R3 have been adjusted to include design/capability based requirements as well as the demonstration of performance during disturbances.	
Stefanie Burke - Portland General Electric Co. - 6	
Answer	Yes
Document Name	
Comment	
PGE supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	

Since the evidence needed is the actual recorded data, we only need it when there's an actual event that happened in the system. What if after the event, we found out that we are not compliant? What can we do to ensure compliance? Please add more clarification about the evidence requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Capability and Performance Measures:** The team agrees and the measures for R1 through R3 have been adjusted to include design/capability based requirements as well as the demonstration of performance during disturbances. **Measures - data:** The compliance measures for demonstration of performance were revised from "actual recorded data" to "actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data".	
Wesley Yeomans - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Katrina Lyons - Georgia System Operations Corporation - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you.	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	

Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
Not Applicable to Reclamation.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	
BC Hydro appreciates the drafting team's efforts and the opportunity to comment, and offers the following: 1. Requirement R2 Part 2.1.2 appears to set an additional Requirement for TP, PC, RC, or TOP to specify requirements for scenarios where an IBR cannot deliver both active and reactive power when the voltage is within the Continuous Operating Region and below 95%. BC Hydro recommends that if these are intended as mandatory or deemed as a necessary input for the IBR Owner/Operator, then these should be codified as standalone Requirement(s) against the appropriate functional entities (TP, PC, RC, or TOP suggested by the current draft). 2. The VSL Table for Requirement R1 does not reflect the allowance of a documented limitation. As drafted, it implies that a Severe VSL will be assessed in spite of a preexisting and documented equipment limitation. BC Hydro recommends that the wording be revised to clarify the compliance expectations when evaluating IBR performance.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment:
R2 does not intend that values other than the default values must be specified, only that performance for the plant/facility will be evaluated in accordance with those values if provided. If the TP, PC, RC, or TOP require different criteria for system reliability then the flexibility to require GO/TOs to follow those criteria is allowable. Requring planner/operators to provide values when different criteria are not needed was determined to be unnecessary.
VSL: The VSL tables were adjusted to clarify if there is an exemption in place.

3. Do you agree with the drafting team's proposals for including IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in PRC-029-1 Requirements R3, R4, and R5?	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

Designing an IBR plant for transient over-voltage ride-through compliance is complicated by separation of the IBR Units from MPT high side by the non-aggregated collector system including the MPT itself, frequency dependence of the collector system, GSU (i.e., pad mount transformers) and MPT transformer saturation, and surge arrestors on the collector system. DFRs triggered on TOV are essential for monitoring compliance.

Assessing IBR plant phase jump ride-through is dependent on being able to trigger DFR records on non-fault line switching events. Also, as the standard is now written, phase angle jump of any magnitude during a fault must be ridden through and it does not seem possible to determine if a ride-through failure is caused by a fault-caused phase jump exceeding 25 degrees (in which case the IBR could be compliant), or if instead there is a true non-conformity with R1. AEP is not aware if anything can be done about this, but it may be a minor point in most practical situations.

Regarding R4, the technical rationale supporting the standard seems to neglect the possibility of torsional interaction between the wind facilities where sub-synchronous control interaction could exist that can result in possible damage to the wind turbine generator shaft. Therefore, a blanket statement that an inverter-based resource is not affected by off-nominal frequencies may be an assumption that should warrant further considerations when establishing inverter-based resource, frequency ride through requirements. We believe this is supported by page 6 of the technical rationale which states *"In the case of the non-hydraulic turbine synchronous resources, the turbine is usually considered to be more restrictive than generator in limiting IBR frequency ride-through because of possible mechanical resonances in the many stages of turbine blades. Off-nominal frequencies may bring blade vibrational frequencies closer to a mechanical resonate frequency and cause damage due to the vibration stresses. However, inverter- interfaced-IBR does not share this vibrational failure mode."* Furthermore, how should phase jump be considered in R5 where synch check relay settings are greater than 25 degrees?

Likes 0	
Dislikes 0	
Response	

Thank you for your comments. **Previous R3:** The team has removed Requirement R3. **Assessing phase jump:** Previous Requirement R5 has been removed and added as an exemption to Requirement R1. There is no exemption to trip within the no-trip zone for a fault. If there is a trip during non-fault initiated switching events, measurement data taken from the high-side of the MPT would include this information. The measure for R1 has been modified to reflect this change. The analysis is triggered by the plant tripping which is an event included within an analysis required by PRC-030. At a minimum, the DFR should be configured to trigger when a trip or a reduction in active power occurs for PRC-030. **R3 (Previous R4):** R3 requires ride-through only during frequency deviations of the fundamental waveform as described in Attachment 2 (previously Attachment 3) and is, as you correctly observe, the intent of the standard is currently only for the fundamental frequency and does not address other superimposed frequencies including those resulting from sub-synchronous resonances. We expect that the actual phase jump seen at an IBR POI or high side of MPT in the case of a sync-check supervised line reclosing would be substantially less than the pre-reclose angle across the open breaker.“ In most cases and for most sync-check settings, we don’t believe the actual phase jump would be greater than 25 degrees.”

Leah Gully - Madison Fields Solar Project, LLC - 5 - RF	
Answer	No
Document Name	
Comment	
See "additional comments" for details	
Likes 0	
Dislikes 0	
Response	
Thank you for you comment	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	

Tri-State is concerned with the big jump from 61.8 to 64 under Attachment 3, Table 4. We would like to suggest the ride-through requirement be at 62 or 63.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. At this time, there is no change to the table ranges.	
Brian Lindsey - Entergy - 1	
Answer	No
Document Name	
Comment	

- R3:
  - Technical Rationale “High Voltage Ride Through and Low Voltage Ride Through” modes were not clearly defined. “Mode” implies a specific, programmed, set of actions within controls which may not be real for solar sites.
  - A GO may not know if a switching event occurs. In that case, how would a GO be expected to determine if the event in question is a switching event or not? While R6 addresses exemptions for R1 and R2 in the case that equipment or the ability to record doesn’t exist in an existing site, the same may be of concern for the sub-second requirements listed in R3, 4 and 5. The same exclusions should be for the entire standard, if applicable.
- R4:
  - If the Rate of Change of Frequency is 5 Hz/second, there’s concern that the level of calculation needed on parameters that may not have more than a 1/second resolution would net little reaction.
- R5:
  - While R6 addresses exemptions for R1 and R2 in the case that equipment or the ability to record doesn’t exist in an existing site, the same may be of concern for the sub-second requirements listed in R3, 4 and 5. The same exclusions should be for the entire standard, if applicable.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Previous R3: Requirement R3 has been removed.
R3 (previous R4): The team is drafting PRC-029 to align with the proposed requirements for measurements within PRC-028. Additional information on calculating ROCOF has been provided in the technical rationale.
R4 (previous R6): The scope of allowable exemptions within R5 is consistent with the regulatory directives of Order No. 901. Frequency or phase-jump requirements cannot apply for exemption. New IBR cannot apply for exemption.

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
AECI supports comments provided by the NAGF	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to NAGF.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports NAGF's and EEI's comments. Additionally, see "Measures" concern noted above in Q2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI and NAGF. The measures have been addressed per the response in Q2.	
Colin Chilcoat - Invenergy LLC - 6	

Answer	No
Document Name	
Comment	

No, Invenergy disagrees with the proposals for including IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in Requirements R3, R4, and R5. We offer the below comments regarding these Requirements:

R3: Can the drafting team provide data that demonstrates observed overvoltages during recent System events were of the TOV magnitudes and durations defined in Attachment 2 Table 3? TOVs of such scale are primarily due to the following three scenarios: 1) a lightning strike on the nearby transmission system, 2) transmission line switching transients, and 3) resonant phenomena like voltage magnification due to shunt capacitor switching on the transmission system. Measures are already in place to mitigate such events, including but not limited to proper insulation coordination and substation design, metal oxide varistors, and proper capacitor bank switching of transmission level shunt capacitors (e.g. synchronous switching or use of pre-insertion resistors to mitigate voltage magnification to the extent possible).

To support our statement above, consider an often-quoted document to support these TOV requirements in the NERC Odessa Disturbance Texas Events: May 9, 2021 and June 26, 2021 Joint NERC and Texas RE Staff Report, Dated September 2021. A detailed read of the section that is entitled Inverter Transient AC Overvoltage Tripping Persists identifies poor coordination of controls and protection as the primary driver of these events, rather than TOV conditions at the point of measurement due to switching transients or any type of resonance. What the report explains is that in some cases the IBR units force maximum reactive power output during a fault to push the network voltages up, then once the fault clears they do not pull back on the reactive power injection quickly enough, which leads to an RMS over-voltage (not switching event TOV) at the terminals of the IBR unit, and thus the IBR units tripped. This is solved by 1) proper controls and protection coordination, 2) proper IBR plant design, and 3) proper evaluation of the LVRT and HVRT ride-through capabilities of the IBR plant during the design phase of the plant.

R3 should be removed, and the focus placed on low voltage ride-through and high voltage ride-through, with an emphasis that both LVRT and HVRT performance should be tested during the design phase of a facility using validated IBR unit models based on type-testing.

R4: In the Technical Rationale, the drafting team explains that due to lower system inertia “a wider frequency ride-through capability for IBR **may** be required to avoid the risk of widespread tripping.” Can the drafting team cite more specific reasoning or data to support the expansion of the frequency ride-through capability requirement to the range of 64Hz to 56Hz, well beyond the IEEE 2800-2022 standard frequency ride-through requirement and the capabilities of many legacy IBRs?

The proposed 6-second frequency ride-through capability requirement for the ranges of 61.8Hz to 64Hz and 57Hz to 56Hz does not align with the requirements on the rest of the BES. For the foreseeable future, synchronous generators will continue to be a significant part of the grid. It is a

well-established fact that such large electric machinery, which are directly connected to the grid, cannot be exposed to such large variations in frequency. Therefore, it does not seem reasonable to ask IBRs to go to such extremes. **R5**: We fail to see the value of requirement R5 given the other ride-through requirements, and it's unclear to us how an entity is to determine if the subject switching event is initiated by a fault or not. Additionally, we don't believe the language in R5.1. regarding equipment tripping to prevent equipment damage is reasonable or auditable. We recommend Requirement R5 is removed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Previous R3:** Requirement R3 has been removed. The poor coordination scenario described is covered within Requirement 2.4 (previously R2.3). There was additional information regarding transient overvoltage within Note 10 of Attachment 1 which would be applicable to Requirements R1 and R2. **R3 (Previous R4)**: **Previous R5:** Previous Requirement R5 has been removed and added as an exemption to Requirement R1. There is <u>no</u> exemption to trip within the no-trip zone <u>for a fault</u>. If there is a trip during non-fault initiated switching events, measurement data taken from the high-side of the MPT would include this information. The measure for R1 has been modified to reflect this change.	
Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	
No, Invenergy disagrees with the proposals for including IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in Requirements R3, R4, and R5. We offer the below comments regarding these Requirements: **R3**: Can the drafting team provide data that demonstrates observed overvoltages during recent System events were of the TOV magnitudes and durations defined in Attachment 2 Table 3? TOVs of such scale are primarily due to the following three scenarios: 1) a lightning strike on the nearby transmission system, 2) transmission line switching transients, and 3) resonant phenomena like voltage magnification due to shunt capacitor switching on the transmission system. Measures are already in place to mitigate such events, including but not limited to proper	

insulation coordination and substation design, metal oxide varistors, and proper capacitor bank switching of transmission level shunt capacitors (e.g. synchronous switching or use of pre-insertion resistors to mitigate voltage magnification to the extent possible).

To support our statement above, consider an often-quoted document to support these TOV requirements in the NERC Odessa Disturbance Texas Events: May 9, 2021 and June 26, 2021 Joint NERC and Texas RE Staff Report, Dated September 2021. A detailed read of the section that is entitled Inverter Transient AC Overvoltage Tripping Persists identifies poor coordination of controls and protection as the primary driver of these events, rather than TOV conditions at the point of measurement due to switching transients or any type of resonance. What the report explains is that in some cases the IBR units force maximum reactive power output during a fault to push the network voltages up, then once the fault clears they do not pull back on the reactive power injection quickly enough, which leads to an RMS over-voltage (not switching event TOV) at the terminals of the IBR unit, and thus the IBR units tripped. This is solved by 1) proper controls and protection coordination, 2) proper IBR plant design, and 3) proper evaluation of the LVRT and HVRT ride-through capabilities of the IBR plant during the design phase of the plant.

R3 should be removed, and the focus placed on low voltage ride-through and high voltage ride-through, with an emphasis that both LVRT and HVRT performance should be tested during the design phase of a facility using validated IBR unit models based on type-testing.

R4: In the Technical Rationale, the drafting team explains that due to lower system inertia “a wider frequency ride-through capability for IBR **may** be required to avoid the risk of widespread tripping.” Can the drafting team cite more specific reasoning or data to support the expansion of the frequency ride-through capability requirement to the range of 64Hz to 56Hz, well beyond the IEEE 2800-2022 standard frequency ride-through requirement and the capabilities of many legacy IBRs?

The proposed 6-second frequency ride-through capability requirement for the ranges of 61.8Hz to 64Hz and 57Hz to 56Hz does not align with the requirements on the rest of the BES. For the foreseeable future, synchronous generators will continue to be a significant part of the grid. It is a well-established fact that such large electric machinery, which are directly connected to the grid, cannot be exposed to such large variations in frequency. Therefore, it does not seem reasonable to ask IBRs to go to such extremes.

R5: We fail to see the value of requirement R5 given the other ride-through requirements, and it’s unclear to us how an entity is to determine if the subject switching event is initiated by a fault or not.

Additionally, we don’t believe the language in R5.1. regarding equipment tripping to prevent equipment damage is reasonable or auditable. We recommend Requirement R5 is removed.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Previous R3: Requirement R3 has been removed. The poor coordination scenario described is covered within Requirement 2.4 (previously R2.3). There was additional information regarding transient overvoltage within Note 10 of Attachment 1 which would be applicable to Requirements R1 and R2.
R3 (Previous R4):
Previous R5: Previous Requirement R5 has been removed and added as an exemption to Requirement R1. There is no exemption to trip within the no-trip zone for a fault. If there is a trip during non-fault initiated switching events, measurement data taken from the high-side of the MPT would include this information. The measure for R1 has been modified to reflect this change

Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	

1 AES CE agrees that such performance criteria in R3, R4, and R5 needs to be included, but requests modifications and clarifications as requested below:

2· The language in R3 and R5 relating to "switching events" is difficult to track from the GO perspective. If such an event occurs at the Transmission Operator (TOP), we may not be aware of the need to track and assess our IBR performance as applicable to PRC-029 unless notified by the TOP. If a performance issue with an IBR is identified we would need to be informed by the TOP that a switching event occurred to assess applicability to PRC-029.

3 Please update the technical rationale to clearly state that the 5 Hz/second criteria in R4 aligns with IEEE2800.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
2. Previous requirement R3 has been removed. Previous R5 does not require to track all switching events. However, Previous R5 has been removed and the non-fault exclusionary language has been added to R1. A requirement to notify the Generator Owner or Transmisson Owner and to evaluate performance when the plant/facility tripped because of a switching event is in the current draft PRC-030.
3. Additional language has been added in the TR.

Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
These requirements would be a huge expense for sites that currently don't have frequency response capabilities and there is a strong possibility that many would not be capable of meeting based on manufactures. It will not be financially feasible for all project owners to support this change. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Frequency response capability is not required by PRC-029.	
George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Invenergy's comments for this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to Invenergy.	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	

Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and North American Generator Forum (NAGF) on question 3	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See responses to EEI and NAGF.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
R5 , First time seeing this type of protective setting, unsure as to whether or not any documentation exists or protective settings currently exist in our fleet for this. M5 , Will the PC's be communicating in writing to the Generator Owner every time there is a disturbance with the request for this data. How long will the data need to be held? The values for ride through are different from PRC-24. All current generation sites have targeted to comply with the curve given in PRC-24. The basis of moving these protective curves are unclear.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. **R5**: The requirements in PRC-029 are not protection or controller setting requirements. Revisions have been to made to include capability based requirements along with performance based requirements. Phase jump protection would typically only be located within the inverter controller and would not be part of requirements for evaluating performance of the full plant/facility; per PRC-030. The documentation could include protection and control settings, manufacturer guidance, engineering analysis, or other guidance on why the trip settings were selected. **M5**: PRC-030 dictates the requirements for entities to send/receive requests for disturbance monitoring data and specifies the retention rate for compliance. The PRC-028 draft specifies data retention requirements for disturbance monitoring data outside of those requests. Ride-through curves: The team identifies that there is reliability need to address IBR technologies with these wider range or ride-through capability, which have demonstrated through multiple reports of wide-area disturbances.	
Joy Brake - Nova Scotia Power Inc. - NA - Not Applicable - NPCC	
Answer	No
Document Name	
Comment	
Yes, they are needed but the understanding of what those criteria should be is not evolved sufficiently at this time. Also, large scale EMT network models are not of sufficient quality to assess the criteria in the design phase. For example, if RoCoF is for a time period of greater than or equal to 0.1 second, it leaves the choice of sample time to the user. The plant can take the 100ms for calculations and meet the criteria. The System Operator criteria may calculate RoCoF over 500ms (as we do) and would see the plant as not meeting criteria for the same event. The proposed RoCoF of 5Hz/s is higher than IEEE1547 Category I, II and III. Transmission Wind turbines and their capabilities are often the same as DER plants. A transmission facility just has a lot more of them. That said, we are looking to introduce higher RoCoF for DER as they may be vulnerable as we transition to a very high IBR grid. RoCoF is not calculated during the fault occurrence and clearance? The standard would only apply for loss of a source of generation without a fault? For loss of our tieline for a fault it would not apply but loss of tieline for neighbouring RAS action it would? It is most needed when there is a fault. For a fault, we are also losing the older wind MW as they go into momentary cessation during the fault making the generation loss greater. For simple loss of supply, a high IBR grid is stronger than for a loss of supply due to fault. We apply RoCoF criteria during a fault. Our current criteria for transmission design is 2.4 Hz/s calculated over 500ms. Our current design criteria for generation facilities ride through is	

4Hz/s. But it is under review in EMT studies. We do not use rolling average at this time as it is difficult to accurately calculate in PSSE. We hope to be able to move to rolling average as we increase our use of PSCAD study results for operational studies.

How does it align with the RoCoF criteria for synchronous plants? We are surveying our existing thermal plants and it is still a bit of an unknown in some areas. Our current criteria of 4Hz/s applies to all generating facilities.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Models: PRC-029 is one part of many standard revisions that are being made to address poor performance. Modeling issues, inclusive of EMT, will be addressed as part Milestone 3 projects (due to be filed Nov 2025).
RoCoF: The requirements within PRC-029 only state the calculation will be of at least 0.1s. Please refer to the Technical Rationale for more information.
Measures - data: The compliance measures for demonstration of performance were revised from "actual recorded data" to "actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data".
Clarification: The requirements to demonstrate ride-through performance are in relation to the response to a fault and include no-trip zones and operation regions to require specific performance during the recovery period, immediately following a fault.
PRC-024 -RoCoF: PRC-024 does include criteria for calculating RoCoF for synchronous machines.

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

The NAGF provides the following comments:

a. Requirement R3 – the NAGF notes that GOs do not have knowledge of BPS/BES "switching events" and requests that the Drafting Team (DT) consider adding a requirement for the TO/TOP to notify the GOs of such events.

b. Requirement R4:

i. The term "applicable IBR" needs clarification.

ii. Request additional clarification/justification regarding the proposed 5 Hz/second threshold.

iii. The NAGF requests clarity on how to test compliance with the TOV Ride-Through requirement during study or plant IBR design phase.

c. Requirement R5:

i. Same concern as identified for R3

ii. The requirements for phase angle shift of 25 degrees should allow IBR tripping if the post-fault system condition is drastically changed and the device protection is activated.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
TOV (previous R3): Previous requirement R3 has been removed.
R3 (previous R4): the term "applicable IBR" has been replaced to refer the applicability section. Additionally, the team has aligned the usage of the 5hz/second criterion with IEEE 2800 and additional clarity has been added to the TR.
R4 (**previous R5**): The evidence of compliance for disturbance monitoring that are associated with voltage and frequency excursions that were System disturbances and would be identified for analysis or another trigger by an applicable entity within draft PRC-030. Evidence of disturbance monitoring of IBR associated with those disturbances would be triggered by compliance under the requirements for PRC-030.

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

- WEC Energy Group disagrees with R3. FERC Order 901 calls for addressing system disturbances. A switching event does not qualify as a system disturbance. In addition, disturbance events summarized this as an anti-islanding protection issue and therefore it should be stated in R3 to reduce confusion. If the SDT decides to keep R3, then R3 should include following text, "unless a documented equipment limitation exists in accordance with Requirement R6."
- WEC Energy Group agrees with inclusion of R4 with following exception: R4 should include following text, "unless a documented equipment limitation exists in accordance with Requirement R6."
- WEC Energy Group agrees with inclusion of R5 with following exceptions:

- R5 should include following text, “unless a documented equipment limitation exists in accordance with Requirement R6.”
- The industry term is known as PLL Loss of Synchronism and is identified as such in disturbance reports. Therefore, R5 should adopt the same to reduce the confusion.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Previous R3: Previous requirement R3 has been removed.
Previous R5: Previous Requirement R5 has been removed and added as an exemption to Requirement R1. There is no exemption to trip within the no-trip zone for a fault. If there is a trip during non-fault initiated switching events, measurement data taken from the high-side of the MPT would include this information. The measure for R1 has been modified to reflect this change**.**
Exemptions: The scope of allowable exemptions within R4 (previously R6) is consistent with the regulatory directives of Order No. 901. Frequency or phase-jump requirements cannot apply for exemption. New IBR cannot apply for exemption. This is consistent with the ordered directives.
PLL loss of synchronism: A footnote has been added to R1 to clarify PLL loss of synchronism.

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

Duke Energy recommends the implementation of EEI and NAGF comments.

Duke Energy also recommends, if not already considered, to verify with OEMs that the inverters can satisfy Att 2. Figure 3 does not align with IEEE 2800 Figure 14; again, making compliance with both requirements more complicated.

The controls only respond to voltage and therefore will have no context of the initiating event as could be implied by the statements in R3 and R5. Recommend adding an exception to R3 worded in a similar format to the exception stated in 5.1.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. See response to EEI and NAGF. **TOV:** Attachment 2 has been removed as well requirement R3. **IEEE 2800**: PRC-029 and IEEE 2800 to not have any contradictory. Requirements within the NERC PRC-029 address the scope of the SAR and draw from IEEE2800 but are mandatory and enforceable requirements; in contrast to IEEE2800.	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
R3-5: R6 should apply to R1-R5 to account for equipment limitations that may also apply to R3-R5. Recommend similar language included in R1 and R2 is added to R3-5: "…unless a documented equipment limitation exists in accordance with Requirement R6." Recommend that there be no requirement to document limitations on legacy equipment and that this standard focuses on equipment brought into service after the implementation date.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Previous R3**: Previous requirement R3 has been removed. **Previous R5:** Previous Requirement R5 has been removed and added as an exemption to Requirement R1. **Exemptions**: The scope of allowable exemptions within R4 (previously R6) is consistent with the regulatory directives of Order No. 901. Frequency or phase-jump requirements cannot apply for exemption. New IBR cannot apply for exemption. This is consistent with the ordered directives.	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	

These requirements would be a huge expense for sites that currently don't have frequency response capabilities and there is a strong possibility that many would not be capable of meeting based on manufactures. It will not be financially feasible for all project owners to support this change. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The scope of allowable exemptions within R4 (previously R6) is consistent with the regulatory directives of Order No. 901. Frequency or phase-jump requirements cannot apply for exemption. New IBR cannot apply for exemption. This is consistent with the ordered directives.	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	No
Document Name	
Comment	
No technical expertise to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	No
Document Name	
Comment	

Vistra agrees with AEP.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to AEP.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
On behalf of the SERC Generator Working group: Apply the R1 and R2 phrase "…unless a documented equipment limitation exists in accordance with Requirement R6" to R3, R4, and R5 in addition to what is currently proposed in R1 and R2. For R3 and R5, the GO will not know an over-voltage or phase jump is the result of a non-fault switching event, so is the GO expected to treat all over voltage and phase jump events as non-fault events.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Exemptions:** The scope of allowable exemptions within R4 (previously R6) is consistent with the regulatory directives of Order No. 901. Frequency or phase-jump requirements cannot apply for exemption. New IBR cannot apply for exemption. This is consistent with the ordered directives. **Previous R3:** Previous requirement R3 has been removed. **R4 (previous R5)**: R4 does not require to track all switching events. The requirement to notify the Generator Owner or Transmisson owner and to evaluate performance when the plant/facility tripped because of a switching event is in the current draft PRC-030. Coordination between PRC-029 and PRC-030 drafting teams: these team have implemented changes to those drafts that triggers within PRC-030 to initiate an analysis will be	

evaluated against PRC-029 ride through criteria. PRC-029 established the criteria and PRC-030 includes requirements for conducting the analysis of performance after a disturbance.

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	

Comment

R5.1:

This requirement is beyond the purpose of the standard, which is to establish Frequency and Voltage Ride-through Requirements for Inverter - Based Generating Resources and should be removed.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Previous R5: Previous Requirement R5 has been removed and added as an exemption to Requirement R1. There is no exemption to trip within the no-trip zone for a fault. If there is a trip during non-fault initiated switching events, measurement data taken from the high-side of the MPT would include this information. The measure for R1 has been modified to reflect this change.

Carey Salisbury - Santee Cooper - 1,3,5,6, Group Name Santee Cooper

Answer	No
Document Name	

Comment

For R3 and R5, the GO will not know an over-voltage or phase jump is the result of a non-fault switching event, so is the GO expected to treat all over voltage and phase jump events as non-fault events.

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. **Previous requirement R3** has been removed. **R4 (previous R5): R4** does not require to track all switching events. The requirement to notify the Generator Owner or Transmisson owner and to evaluate performance when the plant/facility tripped because of a switching event is in the current draft PRC-030.	
Michael Goggin - Grid Strategies LLC - 5	
Answer	No
Document Name	
Comment	

There are several concerns with the equipment limitation exemption language in the draft of R6, and such exemptions not being allowed for R3 and R5. To justify R6 only allowing an equipment limitation exemption for existing resources to R1 and R2, and not the other requirements of PRC-029, the NERC drafting team's technical rationale document points to FERC Order 901:

The objective of Requirement R5 [sic] is to ensure legacy IBR may need to obtain an exemption to the voltage ride-through requirements if hardware replacements or other costly upgrades would be necessary to comply with Requirements R1 or Requirement R2… FERC Order No. 901 states that this provision would be limited to exempting "certain registered IBRs from voltage ride-through performance requirements." This is the reason that no similar provisions are included for exemptions for frequency, rate-of-change-of-frequency (ROCOF), phase angle change ride-through requirements.

First, the R6 equipment limitation exemption should also apply to R3, which requires ride-through for "a transient overvoltage as a result of a switching event whereby instantaneous voltage at the high-side of the main power transformer exceeds 1.2 per unit." As NERC notes, FERC Order 901 directed NERC that existing resources can have equipment limitation exemptions from voltage ride-through requirements, and remaining online during transient over-voltage is clearly a voltage ride-through requirement. Transient over-voltage can damage equipment, so allowing IBRs to protect against this damage is consistent with FERC's intent in Order 901 to only allow tripping that is necessary to protect equipment. Moreover, in many cases making existing equipment better able to withstand transient overvoltages would require replacing or modifying hardware.

For similar reasons, an equipment limitation exemption for existing resources should also apply to R5, which requires ride-through for voltage phase angle changes of less than 25 degrees. FERC Order 901 directed NERC that existing resources can have equipment limitation exemptions from voltage ride-through requirements, and remaining online during voltage phase angle changes should be interpreted as part of voltage ride-through requirements. Remaining online during phase angle changes of less than 25 degrees could be a problem for existing generators, particularly wind generators as phase angle changes can impose mechanical stresses on the wind turbine's rotating equipment. Not allowing an

equipment limitation exemption for existing generators under R5 is particularly problematic as it is not typically feasible to retrofit existing wind turbines to increase their ability to withstand mechanical stresses due to phase angle changes. In such cases, making existing equipment better able to withstand voltage phase angle changes would require replacing or modifying hardware. Phase angle changes can damage equipment, so allowing IBRs to protect against this damage is consistent with FERC's intent in Order 901 to only allow tripping that is necessary to protect equipment. Moreover, a contextual reading of Order 901 indicates FERC was mostly focused on limiting equipment limitation exemptions to existing generators that would have to physically replace or modify hardware, and not strictly limiting such exemptions to a narrow reading of what constitutes voltage ride-through requirements. Paragraph 193 in its entirety, and particularly the first sentence, explain that FERC's intent was focused on exempting existing resources that would have to physically replace or modify hardware: "we agree that a subset of existing registered IBRs –typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements directed herein." FERC continued by directing that "Any such exemption should be only for voltage ride-through performance for those existing IBRs that are unable to modify their coordinated protection and control settings to meet the requirements without physical modification of the IBRs' equipment."{C}[1] As explained above, equipment limitation exemptions for R3 and R5 are likely necessary to ensure some existing generators do not have to physically replace or modify hardware, and thus such exemptions are consistent with FERC's directive in Order 901. Finally, R6 equipment limitation exemptions should be allowed for resources with signed interconnection agreements as of the effective date of the Standard, instead of resources that are in-service as of that date. Resource equipment decisions are typically locked down at the time the interconnection agreement is signed, and a change in requirements after that point can require a costly change in equipment or settings that may also trigger a material modification and resulting interconnection restudies. The implementation plan for PRC-029 indicates that the effective date for the Standard will be the first day of the first quarter six months after FERC approval. Many resources take significantly longer than that to move from a signed interconnection agreement to being placed in service, so it makes more sense to allow R6 equipment limitation exemptions for resources that have a signed interconnection agreement as of the effective date of the Standard. {C}[1]{C} Order 901, https://www.ferc.gov/media/e-1-rm22-12-000, at paragraph 193	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. **Previous R3:** The team agrees and previous requirement R3 has been removed. **Previous R5:** Previous Requirement R5 has been removed and added as an exemption to Requirement R1. There is no exemption to trip within	

the no-trip zone for a fault. If there is a trip during non-fault initiated switching events, measurement data taken from the high-side of the MPT would include this information. The measure for R1 has been modified to reflect this change. **Exemptions**: The scope of allowable exemptions within R4 (previously R6) is consistent with the regulatory directives of Order No. 901. Frequency. Newly interconnecting IBR cannot apply for exemption and "legacy IBR" is generally understood to include those IBR that are "in-service". This is consistent with the ordered directives.	
Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

A premise of R3 is knowing of a transient OV, due to a switching event on the transmission system.   The Generator Owner is not going to have the intelligence to know if a transient OV is due to a switching event. So, is the GO expected to treat all OV events as non-switching events?

1. Requirement R3: The Transient Overvoltage Ride-Through requirement is just not ready to be included in a regulatory standard. The measure for this requirement is based on actual recorded data. The existing facilities may not even have recording equipment in place to measure switching transients. The IEEE P2800.2 WG has also struggled to come up with a Design Evaluation procedure to show that the plant would be able to ride-through the specified TOV ride-through requirements.
2. Requirement R4:
    - The intent of "continue to exchange current" is understood, however, the requirement is vague. During frequency excursion events, it is necessary that IBR adjusts active power output in response to frequency deviation. But these details are not necessary in NERC standards, currently. The IBR that "continues to exchange current" but not based on frequency deviation, would comply with the standard requirements, which is not ideal. The TP/PC is expected to specify IBR performance during abnormal system frequency. Hence, the requirement should read as following: Each GO or TO of an applicable IBR shall ensure each IBR remains electrically connected and continues to exchange current **as specified by TP or PC** during a frequency excursion event……
    - Why is there no exception for Volts/Hz limit? This could be an issue for type III WTG and transformer within the plant. The frequency ride-through requirement in the IEEE Std 2800 recognizes Volts/Hz limitation.
3. Requirement R5:
    - Consider revising to read as follows: Each GO or TO of an applicable IBR facility shall ensure that each IBR remains electrically connected and continues to exchange current during non-fault switching events where the instantaneous change in positive sequence voltage phase angle is less than or equal to 25 electrical degrees at the high-side of the main power transformer.
    - Has the SDT discussed how to measure "instantaneous" phase angle jump based on recorded data?

- Part 5.1 is not necessary. The IBR may not trip because it measured phase angle jump of greater than 25 electrical degrees but may trip due to affects of such a jump in phase angle. Not sure how to even prove that equipment was at risk or not.
- For R5, the GO will not know if a phase jump is the result of a non-fault switching event, so is the GO expected to treat all phase jump events as non-fault switching events?
- In R5, what happens if an IBR trips due to phase angle jump while the frequency and voltage remain in the continue to operate range? IBRs will not know whether the system has experienced a fault or not.

4. Attachment 3:
    - Why does the SDT require more stringent ride-through capability compared to the IEEE Std 2800? If a certain interconnection requires stringent ride-through requirement then it should only be required for that interconnection. There is no need to extend the stringent requirements of one interconnection to all interconnections. Such an approach is implemented in the PRC-024, PRC-006, etc. Additionally, the PRC-006 specifies boundaries between which the frequency needs to remain while simulating and designing UFLS scheme. The IBR frequency ride-through coordinated with boundaries in PRC-006 should be enough.
    - Table 4:
        - Not sure what is implied by “average system frequency”. The term “average” makes sense when associated with ROCOF but not with frequency.
        - ≥64 should be >64
        - ≥61.8 should be >61.8
    - Note 1 is not necessary. Which measurement is taken on each phase?
    - Note 2: Consider replacing with following: Frequency is measured over a period of time, typically 3-6 cycles.
    - Note 3: not sure which “control settings” are referred here. Consider the following from PRC-024: Instantaneous trip settings based on instantaneously calculated frequency measurement is not permissible.
    - Note 5: Why did the SDT specify 15-min time period instead of 10-min time period in the IEEE Std 2800.

ROCOF and phase angle jumps:

- Some legacy IBRs have technical limitations that will prevent them from riding through ROCOF less than or equal to 5 hz / second or phase angle jumps less than 25 electrical degrees. Such IBRs need the ability to seek an exemption for these requirements.Note: ERCOT has questioned the validity of how ROCOF and phase angle jumps are measured, and whether the 5 hz / second and 25 electric degree values are accurate.
- R5 specifies that IBRs must ride through phase angle jumps initiated by **non-fault** switching events and are changes of less than 25 electrical degrees. There is an issue Southern Company has encountered on NOGRR245. ERCOT has proposed that IBRs not trip for any ROCOF or phase angle jumps during **fault** conditions. It is an understanding that IBRs should ignore ROCOF and phase angle jump values during fault conditions. Southern Company would support similar fault language in PRC-029-1, but a technical exemption would be required because some legacy IBRs are unable to distinguish between a fault and non-fault condition.

R6.1.2 discusses *"aspects of VRT requirements that the IBR would be unable to meet"*. This language could be clearer by requesting the IBR to identify actual VRT capabilities.[A1] M6 requires evidence of equipment limitations prior to the effective date of the standard. This could be extremely challenging to meet. Finally, Southern Company supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Previously R3:** Previous requirement R3 has been removed. Previous R5 does not require to track all switching events. However, Previous R5 has been removed and the non-fault exclusionary language has been added to R1. A requirement to notify the Generator Owner or Transmission Owner and to evaluate performance when the plant/facility tripped because of a switching event is in the current draft PRC-030. **Terminology:** The phrase "continue to exchange current" is consistent if a BESS is charging prior to a fault and providing voltage support after the fault. However, the team agrees that a definition for Ride-through is preferable and has replaced usage of "continue to exchange current". **R3 (Previously R4):** Previous requirement R4 does not require additional performance requirements beyond ride-through capability. Other 901 related Standards Projects are expected to address. The scope of allowable exemptions within R4 (previously R6) permits a Volts/Hz-related exemption but in general the IBR should regulate voltage to avoid exceeding Volts/Hz limitations during an underfrequency event. **Previous R5:** Previous Requirement R5 has been removed and added as an exemption to Requirement R1. There is no exemption to trip within the no-trip zone for a fault. If there is a trip during non-fault initiated switching events, measurement data taken from the high-side of the MPT would include this information. The measure for R1 has been modified to reflect this change. Previous R5 does not require to track all switching events. Previous R5 has been removed and the non-fault exclusionary language has been added to R1. A requirement to notify the Generator Owner or Transmission Owner and to evaluate performance when the plant/facility tripped because of a switching event is in the current draft PRC-030. **Attachment 3:** Please refer to the technical rationale for why the approach was taken for Regional variants. Other Regional variants are able to be pursued by each Region as needed. **Table 4:** The word "averaged" has been removed from the title of Table 4. **Note 1:** The team agrees and has removed the "each phase" language. **Note 2**: The language was modified as suggested. **Note 3**: PRC-029 is a performance-based Standard and does not require specific equipment settings. **Note 4:** The 15 minutes was included to coincide with Table 4 as the maximum defined time intervals is 11 minutes (660 seconds). **Phase Jump:** The phase jump requirement (previously R5) has been removed and moved into the scope of R1. The scope of allowable exemptions within R4 (previously R6) is consistent with the regulatory directives of Order No. 901. This is consistent with the ordered directives.	

ROCOF: Please refer to the Technical Rationale for more details on the team's decisions for RoCoF and phase jump criteria. Similarly, this has been brought into the scope of R1.
R4 (Previously R6): Requirement R4 has been revised to include additional clarity on equipment capability as requested information. Additionally, the scope of allowable exemptions must be for known equipment limitations. The implementation plan for R4 does include an additional 6 month window to communicate those known limitations.

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	

Comment

Rwquirement 3

PG&E believes specific requirements for the inverter capabilities should be removed from the NERC standard and left to the IEEE 2800-22 standard for inverter specifications. The utility relies on RMS measurements and does not have a means to accurately measure transient over-voltage conditions for protective relays; therefore, it would be extremely difficult for the entity to prove its compliance.

Requirement 4

Frequency ride-through limits have been raised considering that IBRs can continue to generate. For synchronous machines, it is not possible to have such a wide frequency range (as per attachment 3 copied below). When the system has majority of IBRs, the effect on synchronous machines with such wide frequency variations is unknown. Also, it would affect the underfrequency load shedding schemes.

PG&E has the following questions for the SDT to consider: Should there be separate ride through limits for Grid Forming inverters and Grid Following inverters? Would higher penetration of IBRs affect the allowable frequency ranges?

Requirement 5

PG&E believes specific requirements for the inverter capabilities should be removed from the NERC standard and left to the IEEE 2800-22 standard for inverter specifications.

PG&E has the following question for the SDT: how do we set relays or trigger a DFR for a switching/non-fault event to show compliance with the requirement?

Likes 0	
Dislikes 0	
Response	

Thank you for your comment.
Previous R3: Previous requirement R3 has been removed.
R3 (previous R4): The team agrees with the comment regarding R4. The team does not propose including different requirements/standards for forming/following type inverter technology.
Previous R5: Previous Requirement R5 has been removed and added as an exemption to Requirement R1. There is no exemption to trip within the no-trip zone for a fault. If there is a trip during non-fault initiated switching events, measurement data taken from the high-side of the MPT would include this information. The measure for R1 has been modified to reflect this change. Previous R5 does not require to track all switching events. However, Previous R5 has been removed and the non-fault exclusionary language has been added to R1. A requirement to notify the Generator Owner or Transmission Owner and to evaluate performance when the plant/facility tripped because of a switching event is in the current draft PRC-030.

Mark Flanary - Midwest Reliability Organization - 10

Answer	No
Document Name	
Comment	

See comments below under question 4.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment.

Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	2020-02_EPRI Comments on Draft NERC PRC-029 (IBR ride-through) Reliability Standard.pdf
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The team believes these comments have been sufficiently addressed in other comment responses.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
We agree that PRC-024 standard should remain (enforced) because this will also help in ensuring the reliability of the Bulk Power System.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
The IESO recommends the following modifications to the text improve clarity or to better convey intent. **With regards to R4:** "…continues to exchange current during a frequency excursion event whereby the **system** frequency remains within the "no trip zone" according to…"	

This suggestion would differentiate the actual system frequency from, say, the frequency measurement as 'seen' by the PLL or other parts of the controls.

With regards to 5.1

As commented above, IESO believes 'not tripping except to provide equipment protection' warrants a dedicated Requirement, which may be referred to the context of other requirements, such as performance during phase angle jumps.

Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	

Response

Thank you for your comment.
R3 (Previous R4): R3 has been modified to include the revision as suggested.
Previous R5: Previous Requirement R5 has been removed and added as an exemption to Requirement R1. There is no exemption to trip within the no-trip zone for a fault. If there is a trip during non-fault initiated switching events, measurement data taken from the high-side of the MPT would include this information. The measure for R1 has been modified to reflect this change.

Michael Brytowski - Great River Energy - 3

Answer	Yes
Document Name	

Comment

Comments: Initial review indicates the proposed requirements R3, R4 and R5 align with IEEE 2800 which we support.

R3: we suggest adding to attachment 2 how the instantaneous transient overvoltage should be calculated (such as what the pu base? and the minimum sampling rate?)

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
Previous R3: Previous requirement R3 has been removed. Information on the TOV calculation has been added to Attachment 1.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no issue for the direction of these requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Stefanie Burke - Portland General Electric Co. - 6	
Answer	Yes
Document Name	
Comment	
PGE supports EEI's comments but in addition would add clarification: For the requirement to say "may trip, but shall only trip to prevent equipment damage" does not provide clear direction. If the IBR can stand a 30 electrical degree change, is it acceptable to trip at 25.0 to prevent equipment damage? It would be preferrable to provide a safety margin before reaching the damage point. Or, is this stating that the IBR wait until 30.0 electrical degrees is reached before taking action? What is the measure for making sure an IBR does not trip at 25.0 or above except to protect the equipment? If there is nothing particularly harmful about tripping an IBR above 25.0, why not indicate that above 25.0 is not a "Must Trip Zone/Criteria"?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI. **R2.5**: The team agrees with removing requirements on operation outside the must Ride-through zone and has removed R2.5.	

Previous R5: Previous Requirement R5 has been removed and added as an exemption to Requirement R1. If there is a trip during non-fault initiated switching events, measurement data taken from the high-side of the MPT would include this information. The measure for R1 has been modified to reflect this change. **Capability and Performance Measures**: The team agrees and the measures for R1 through R3 have been adjusted to include design/capability based requirements as well as the demonstration of performance during disturbances.	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
R3: we suggest adding to attachment 2 how the instantaneous transient overvoltage should be calculated (such as what the pu base? and the minimum sampling rate?)	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Previous R3:** Previous requirement R3 has been removed. Information on the TOV calculation has been added to Attachment 1.	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	

Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS supports the following comments that were submitted by EEI on behalf of its members: EEI supports the proposal to include IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in PRC-029-1 Requirements R3, R4, and R5. However, the following phrase “of an applicable IBR” should be removed from R3, R4 and R5. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposal to include IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in PRC-029-1 Requirements R3, R4, and R5. However, the following phrase “of an applicable IBR” should be removed from R3, R4 and R5. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The team agrees and has removed the word “applicable”.	

Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
Maozhong Gong - GE - GE Wind - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
But we need to consider old units, please see the additional comments below.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The scope of allowable exemptions within R4 (previously R6) is consistent with the regulatory directives of Order No. 901. New IBR cannot apply for exemption. This is consistent with the ordered directives.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	

R3: MP agrees with the NSRF's comments on defining the transient overvoltage calculation method. MP also suggests defining the term "current block mode."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Previous R3 has been removed. Information on the TOV calculation has been added to Attachment 1.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG supports IESO's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to IESO.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. See response to EEI.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
However, please verify the ROCOF with regards to how FR data at the IBR Unit level (per the definitions proposed by 2020-06) is required to be captured (Per proposed PRC-028-1). Note that PRC-002-4 and -5 have ROCOF triggers for recording that are significantly different than 5 Hz/second. Measure 4 of PRC-029-1 has a reference to a Planning Coordinator's area but Requirement 4 has no such limitation or uses Planning Coordinator within the language. It appears that the stated ROCOF is high based on IRPT reports (https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf). And the ROCOF definition is different from said report by the IRPTF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. **Measurement Data:** Per the current draft of PRC-028, FR data is not required to be collected below the plant level. **RoCoF:** The team believes that the ROCOF and calculation are appropriate and consistent with other industry measures (e.g. IEEE 2800). Additional information can be found in the technical rationale. **RoCoF - trigger levels**: The team is aware of the trigger levels in PRC-002 are lower than 5 Volts/Hz, which is acceptable. **Terminology:** The Requirement language for Requirements R1, R2, and R3 (previous R4) have been adjusted to "adhere to Ride-through requirements" and no longer reference the PC.	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	

NextEra aligns with EEI's comments: EEI supports the proposal to include IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in PRC-029-1 Requirements R3, R4, and R5. However, the following phrase "of an applicable IBR" should be removed from R3, R4 and R5. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Previous R3:** Previous requirement R3 has been removed. Information on the TOV calculation has been added to Attachment 1. **Previous R5:** Previous Requirement R5 has been removed and added as an exemption to Requirement R1. The word "applicable" was also removed from the requirement language.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT joins the comments of the IRC SRC and adopts them as its own in addition to the following comments, except to the extent of any specific differences between the SRC comments and the following comments from ERCOT. Footnote 2 is not clear as to whether RoCoF measurement should begin immediately or upon fault clearing. IEEE 2800.2 discussions are heading in a direction that would indicate that during fault occurrence, clearance, and recovery back to a steady-state operating point, failure to ride through should only be allowed if the voltage is beyond the requirement (i.e., the unit should not trip due to any perceived RoCoF during the entire disturbance and recovery period). This is similar for phase angle jump. Requirement R4 may need to include language similar to that found in Requirement R5, Part 5.1 to ensure RoCoF is set to the equipment capability and is not arbitrarily set at 5 Hz/s. ERCOT also notes that the IEEE 2800-2 drafting team is identifying that there should be agreement between unit owners and planners/operators on how to measure RoCoF (at what time points, greater than or equal to .1 second) to ensure consistency in testing, model validation, application, and performance evaluation. Otherwise, such a requirement may create confusion or	

otherwise be unenforceable. IEEE 2800-2 also identifies the potential need for higher RoCoF requirements, which may be appropriate in smaller Interconnections.

The current language in Requirement R5 excludes voltage phase angle change of exactly 25 degrees, which is included in IEEE2800 requirements:

SDT's proposed language:

"Each Generator Owner or Transmission Owner of an applicable IBR shall ensure each IBR remains electrically connected and continues to exchange current during instantaneous positive sequence voltage phase angle changes **that are initiated by non-fault switching events on the transmission system and are changes of less than 25 electrical degrees at the high-side of the main power transformer.**"

ERCOT's proposed language:

Each Generator Owner or Transmission Owner of an applicable IBR shall ensure each IBR remains electrically connected and continues to exchange current during instantaneous positive sequence voltage phase angle **changes of 25 electrical degrees or less at the high-side of the main power transformer that are initiated by non-fault switching events on the transmission system**.

Finally, ERCOT believes that under the Violation Risk Factor guidelines, Requirements R3, R4, and R5 should have a VRF of High as they are requirements "**that, if violated, could directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures** . . . ."

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
ROCOF: Footnote 7 clarifies that ROCOF should not be measured during the fault or fault clearnce. The R3 (previous R4) requirement is only applicable to frequency excursions. Ride-through during a voltage excursion would be covered under requirements R1 and R2. Ride-through expectations within R1 and R2 are independent of ROCOF.
The technical rationale has been adjusted to include additional language on setting ROCOF trigger points appropriately and not arbitrarily. The reference to prevent equipment damage (previous R2.5) has been removed from the Standard based on previous comments.
Previous R3: Previous requirement R3 has been removed. Information on the TOV calculation has been added to Attachment 1.
Severity Level: R3 (Previous R4) has been adjusted to a High as suggested.
Previous R5: This requirement has been removed and added as an exemption to Requirement R1.

Kinte Whitehead - Exelon - 3

Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Overall, we at ACES support Requirements R3 through R5; however, we have a minor concern with the wording of Requirement R3, Option 2. Specifically, we have concerns with the requirement to "restart current exchange within 5 cycles of the instantaneous voltage falling below (and remaining below) 1.2 per unit." For how long of a duration should the instantaneous voltage remain below 1.2 p.u. to trigger the 5 cycles wherein the IBR must resume current exchange? We recommend that the SDT consider adding a time component to the return from the transient overvoltage condition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Previous R3**: Previous requirement R3 has been removed. Information on the TOV calculation has been added to Attachment 1.	
Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	Yes
Document Name	
Comment	
Southwest Power Pool joins the ISO/RTO Council Standards Review Committee comments.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. See response to ISO/RTO Council Standards Review Committee.	
Darcy O'Connell - California ISO - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Initial review indicates the proposed requirements R3, R4, and R5 align with IEEE 2800, which the SRC supports. The SRC recommends the following modifications to the text to improve clarity and to better convey the intent of the standard. Recommended changes to R4: "…continues to exchange current during a frequency excursion event whereby the **system** frequency remains within the "no trip zone" according to…" This revision would clarify that the actual system frequency is the relevant measurement instead of the frequency measurement as 'seen' by the PLL or other parts of the IBR control system. Recommended changes to R5.1 As noted above, the SRC believes 'not tripping except to provide equipment protection' warrants a dedicated Requirement, which may be referred to in the context of other requirements, such as performance during phase angle jumps.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. **Previous R3**: Previous requirement R3 has been removed. Information on the TOV calculation has been added to Attachment 1. **R3 (previous R4):** The team agrees and has incorporated the change as suggested. **Previous R5**: Previous Requirement R5 has been removed and added as an exemption to Requirement R1.	

Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting	
Answer	Yes
Document Name	
Comment	
Yes. The SDT should consider citing IEEE 2800-2022 directly in the standard and consider using the IEEE 2800-2022 ride-through requirements as a means to comply with Requirements R1-R5 instead of using Attachment 1 of the standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Requirements within the NERC PRC-029 address the scope of the SAR and draw from IEEE2800 but are mandatory and enforceable requirements; in contrast to IEEE2800. NERC Standards cannot refer to outside sources for the purposes of requirement language, per the Rules of Procedure.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Brittany Millard - Lincoln Electric System - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you.	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
David Campbell - David Campbell On Behalf of: Natalie Johnson, Enel Green Power, 5; - David Campbell	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you.	
Shonda McCain - Omaha Public Power District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Katrina Lyons - Georgia System Operations Corporation - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Wesley Yeomans - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	

Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
Not Applicable to Reclamation.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Imane Mrini - Austin Energy - 6, Group Name Austin Energy	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you.	

4. Provide any additional comments for the Drafting Team to consider, if desired.

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	
Document Name	
Comment	
The proposed PRC-029 seems vague and does not specify what size IBR would applicable. If it is below the 75MVA aggregate, then I believe that would cause undue burden on utilities to meet.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.	

Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting	
Answer	
Document Name	
Comment	

Attachment 1 needs a few corrections.

- Figures 1 and 2 use a logarithmic time scale for the Time x-axis. This should be updated to be a regular non-logarithmic time scale.
- There are numerous inconsistencies in this standard language and Attachment 1 when compared to IEEE 2800. These should be considered and reviewed for clarity and completeness in the standard. The option to cite IEEE 2800-2022 and use the requirements in the IEEE 2800-2022 directly should be allowed over just the use of Attachment 1 (give each GO/TO the ability to use either of these guides to base their performance off of).

- IEEE 2800 identifies the following items, but the standard does not support. Clarification/review should occur for each of these items:
  - Exceptions for Negative-sequence voltage exceeding thresholds
  - IEEE 2800 recognizes Volts/Hz limitations, but the standard does not.
  - IEEE 2800 recognizes 500kV system voltages are actually operated in the range of 525kV and therefore has equipment rated to 550kV. These 500kV operating conditions should be considered in the standard.
  - In IEEE 2800 the frequency ride-through criteria defines 10-minute time periods whereas the standard defines them in a 15 minute time period (Table 4 of Attachment 3). This should be clarified and identified.

The standard is quite vague in terms of technical limitations and documentation exemptions to the requirements. Experience has shown that this is a highly nuanced and difficult consideration. There is no language focused on software versus hardware limitations and what is allowed/expected. This could lead to inconsistent, subjective auditing practices rather than clear objective requirements and auditing.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Attachment 1: The figures have been updated/corrected. The logarithmic scale has been removed.
IEEE 2800 – negative sequence: The PC/TOP/RC/TP are able to provide specific operational criteria beyond the requirements within R2.
Attachment 1 clarification on 500kv: Attachment 1 sets the minimum expectation for operation regardless of voltage class. Expanding the no trip zone for 500kV may still be done based on the system need.
Attachment 1: The tables and figures in Attachment 1 have been updated for consistency. The continuous operating region applies for beyond 10 seconds. Note 9 in Attachment 1 is an exception of the overall requirement.
Attachment 3: Note 4: The 15 minutes was included to coincide with Table 4 as the maximum defined time intervals is 11 minutes (660 seconds); which 10 minute does not sufficiently cover.
Exemptions: Language has modified within the Requirement R4 (previous R6), Implementation Plan, as well as the Technical Rationale. Software-based limitations are not subject to potential exemption.

Darcy O'Connell - California ISO - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee

Answer	
Document Name	

Comment

The SRC requests several enhancements to **PRC-029**.

1. **Clarify and emphasize that documented equipment limitations under Requirement R6 must not be construed to be complete exemptions from the Requirements of PRC-029.** If entities are unable to ride-through portions of the ride-through curve, this should not automatically exempt them from complying with the balance of the ride-through curve as described in the Technical Rationale. While this is clearly expressed in the Technical Rationale for Requirement R6 (page 9), this point needs to be brought out more clearly in the PRC-029 standard itself.
2. **Expand PRC-029 to require that Corrective Action Plans be developed and implemented to remove equipment limitations within a specified timeline or require a** technical justification that addresses why corrective actions will not be applied nor implemented.
3. PRC-029 will need to explicitly require any new inverter/controller replacing older equipment to be compliant with PRC-029 rather than set to original equipment specification.
4. Applicability:In Introduction, Section 4.2.2, it is not obvious what aspect of 'IBR Registration Criteria' makes an IBR an 'applicable' IBR – is it simply that an IBR meets NERC Registration Criteria? This bullet point should be elaborated upon to ensure clarity.
5. Event-Based Standard: The SRC has concerns that this standard is an event-based standard that does not necessarily provide an assurance of reliability before events occur, such as would be provided by having an engineering analysis or results from bench-testing and real-time simulations of control equipment that indicate that successful ride through of prescribed disturbances is expected.
6. Without disturbance events that show whether IBRs perform properly, there is no way to determine if an IBR is compliant with the standard. At a minimum, the measures (e.g, M2-M5) should be extended to indicate that a statement that no such events are known to have occurred will qualify as evidence of compliance.
7. Presentation of Ride-Through Ranges: The intended ride-through requirements would be made more clear if the 'minimum ride-through times' were associated with precisely stated, *non-overlapping ranges* of voltages or frequencies, such as in the example 'Table 2' provided by the SRC in its comments above.
8. Nominal Voltages: Note #4 of Attachment 1 would be clearer if the 'nominal' system voltage values were listed as they are in Attachment 2 of PRC-024-3, i.e., "(e.g., 100 kV, 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 400 kV, 500 kV, 765 kV, etc.)"
9. Harmonize Tables, Figures, Requirements: The voltage/frequency excursion levels and the associated minimum ride-through times for all tables, figures, and any associated performance requirements that modify the requirements should be carefully reviewed and harmonized. There are presently some conflicting entries in the tables/figures.
10. PRC-029 introduces new terms. The drafting team should consider using these new terms in PRC-024 for consistency. The ranges in these definitions may be specific to IBRs due to their unique performance characteristics, but these regions serve the same purpose for synchronous generators.
    i. Term(s):
    ii. Continuous Operating Region – The range of voltages, measured at the high-side of the main power transformer, that are ≥ 0.9 per unit and ≤ 1.1 per unit.

iii. Mandatory Operating Region – The range of voltages, measured at the high-side of the main power transformer, that are > 0.1 per unit and < 0.9 per unit – or – > 1.1 and ≤ 1.2 per unit.
iv. Permissive Operating Region – The range of voltages, measured at the high-side of the main power transformer, that is ≤ 0.1 per unit.

11. There does not seem to be a direct explanation of how these new terms used in the Requirements are applied in Attachment 1, where the ranges for “No-Trip” and “Must-trip” are shown. the only mention of these terms in Attachment 1 appears to be in bullets 8, 9, and 10 where one or two Regions are mentioned and assumed to be understood. Additionally, these terms are not used consistently throughout the standard, as these terms are defined as “Operating Regions,” but frequently appear in the standard as “Operation Regions.” The SRC recommends that the SDT standardize on a consistent format for these terms.

R1. Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that each IBR remains electrically connected and continues to exchange current in accordance with the no-trip zones and operation regions as specified in Attachment 1

Attachment 1

8. The specified duration of the Mandatory Operation Regions and the Permissive Operation Regions in Tables 1 and 2 is cumulative over one or more disturbances within a 10 second time period.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
Exemption: The team agrees that only specific ride-through limitations would be applied and there is no global exemption intended. Language has modified within the Requirement R4 (previous R6) as well as the Technical Rationale to clarify this.
Removing Limitations: The team agrees that replacing equipment associated with the limitation also remove any exemption. This has been clarified in Requirement R4 (previous R6).
Capability and Performance Measures: The team agrees and the measures for R1 through R3 have been adjusted to include design/capability based requirements as well as the demonstration of performance during disturbances.
Applicability: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.
Measures - data: The compliance measures for demonstration of performance were revised from “actual recorded data” to “actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data”.

Measures (events): The evidence of compliance for disturbance monitoring that are associated with voltage and frequency excursions that were System disturbances and would be identified for analysis or another trigger by an applicable entity within draft PRC-030. Evidence of disturbance monitoring of IBR associated with those disturbances would be triggered by compliance under the requirements for PRC-030**.**
CAPs: The analysis of voltage/frequency excursions as well as the development of CAPs are conducted within the PRC-030 draft (project 2023-02).
Ride-through Ranges: The tables in the Attachments have been adjusted to reflect this.
Nominal Voltage: The attachments apply to all system voltages as established by the TOP.
Attachment 1: Tables and Figures in Attachment 1 have been revised to add clarity on the operation regions. The range of values in row #4 of Tables 1 and 2 to clarify the continuous operation region.
Terminology – operating regions: These operating regions have been removed as defined terms. The language of the requirements has been modified to reflect these changes.
Terminology- Ride-through: The team agrees and has defined a new term for Ride-through and replaced language the requirements with this new term. Attachments have also been updated to utilize this term as the "Must Ride-through Zone".
Attachment 1 – corrections: Attachment 1 tables and figures have been revised to clarify the operating regions and no-trip zones.

Mark Flanary - Midwest Reliability Organization - 10

Answer	
Document Name	

Comment

Requirements R1, R2, R3, R4, and R5 and associated Measures do not make it clear whether equipment settings or configurations that render a facility unable to meet the performance requirements constitute a non-compliance prior to the occurrence of an event where the facility fails to meet the performance requirements. An understanding of these requirements as event-based (as described in the current draft of the PRC-029-1 Technical Rationale) would only partially accomplish the risk objectives described in the SAR and in FERC order 901 as many events would not be prevented. This is particularly concerning for frequency excursion events (R4) as these events are relatively infrequent and yet widespread, potentially resulting in the failure of a multitude of IBRs to meet the performance requirements if frequency trip settings are not evaluated preemptively. As such, these requirements should make it clear that facilities are to be configured to meet performance requirements and that the relevant equipment settings should be available as evidence to show compliance.

If there are portions of the performance criteria in this standard that equipment owners cannot be expected to meet through assessment of equipment settings in the absence of an event, those portions should be addressed in separate requirements that specify corrective actions to be performed following an event rather than identify non-compliance at the time of the event.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
Capability and Performance Measures: The team agrees and the measures for R1 through R3 have been adjusted to include design/capability based requirements as well as the demonstration of performance during disturbances.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	

Comment

Attachment 1, Part 2b. I assume that "ESS" means Energy Storage System? Please document or clarify.

Part 7 " … trip …" again. Same question as in comment 2 above. The second sentence is also unclear. What is "the 10-second time period"? Is this phrase identified in Parts 8 and 9? If so, please define it before first use and use the same phrase subsequently.

Attachment 2 Part 3 " … trip …" again. Same question as in comment 2 and Attachment 1 Part 2b above.

Attachment 3, Table 4 Part 2. I agree with averaging frequency over a set time period. But 3 cycles seems rather short to assure a reasonable frequency value, especially during fault conditions. IEEE 2800 says "… at least 0.1 sec" [6 cycles] for ROCOF, and that is probably a good target for frequency also.

Table 4 and Part 4 " … trip …" again. Same question as in comment 2 and Attachment 1 Part 2b and 3 above.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Attachment 1 – ESS correction: the note has been revised to "BESS".
Attachment 1 and 3 – clarification 10 seconds: Notes 8, 9, and 10 (previous notes 7, 8, and 9) now state "any 10 second…".
Previous Attachment 2: Previous Attachment 2 and previous requirement R3 have been removed.

Attachment 2 (previous attachment 3): Notes and the table have been modified to remove reference to "averaging".
RoCoF: The team aggrees that the calculation is for at least 0.1 seconds and is included in footnote 8.

John Pearson - ISO New England, Inc. - 2	
Answer	
Document Name	
Comment	

The new or modified terms should define what the "voltage" is, RMS, Positive Sequence? Instantaneous? Etc. for Continuous Operating Region, Mandatory Operating Region and Permissive Operating Region.

In Attachment 1, bullet 3 is problematic, basing the applicable table based on direction by the Transmission Planner needs to have a specific requirement describing how that would be done. Bullet 4 is also problematic for the same reason. Bullet 8 – Mandatory Operation Regions should conform with IEEE 2800 7.2.2.4 for consecutive disturbances, and differentiate from dynamic voltage oscillations. Bullet 9 should also conform to IEEE 2899 7.2.2.4.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Terminology – voltage: The operating region definitions have been removed as defined terms. The language of the requirements has been modified to reflect these changes. The voltage referenced in Tables 1 and 2 are clarified in Notes 5 and 6 (previous Notes 4 and 5).
Attachment 1 – : The team agrees. Notes for applicability for Tables 1 and 2 are now more specific.
IEEE: The team acknowledges that there may be different requirements required.

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	
Document Name	
Comment	

Southwest Power Pool joins the ISO/RTO Council Standards Review Committee comments.

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response RTO Council Standards Review Committee.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	

- It is the opinion of ACES that Section 4.2 should be modified to utilize the registration criteria as defined in the latest revision of the NERC Rules of Procedure.

Thus, we recommend the following revisions to Section 4.2:

4. Applicability:

4.1 Functional Entities:

4.1.1 Generator Owner that owns an applicable facility in Section 4.2.1.

4.1.2 Transmission Owner that owns an applicable facility in Section 4.2.3.

4.2 Facilities:

4.2.1 Either of the following Inverter-Based Resource (IBR)1 types:

4.2.1.1 BES IBR

4.2.1.2 non-BES IBR that is:

4.2.1.2.1 Connected to the Bulk Power System, and

4.2.1.2.2 Meets the criteria for a Category 2 GO facility.

4.2.2 High-voltage Direct Current (VSC-HVDC) Transmission facilities that serve as a dedicated connection for an Inverter-Based Resource meeting the criteria of 4.2.1.1 • Transmission is a defined term in the NERC Glossary of Terms. As it is currently defined, this term does not specify a voltage threshold for its applicability; therefore, we recommend capitalizing all uses of the word "transmission" within PRC-029-1 for the sake of clarity.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.	
Katrina Lyons - Georgia System Operations Corporation - 4	
Answer	
Document Name	
Comment	
GSOC supports Georgia Transmission Corporation (GTC) Comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to GTC.	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	
Document Name	
Comment	

See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See EEI comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
Kinte Whitehead - Exelon - 3	
Answer	
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. See response to EEI.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

ERCOT joins the comments of the IRC SRC and adopts them as its own in addition to the following comments, except to the extent of any specific differences between the SRC comments and the following comments from ERCOT.

The proposed changes to PRC-024 create a reliability gap, as Type 1 and Type 2 wind turbines are not synchronous machines and would therefore no longer be required to comply with PRC-024 but are not included in PRC-029 because they are not IBRs. The SDT should consider including a specific requirement in PRC-024 or PRC-029 that addresses this technology and requires these types of units to try to meet requirements up to their equipment limitations, to notify their PC/TP/RC/TOP of such limitations, and to reflect any such limitations in their dynamic models. This will ensure that the PC/TP/RC/TOP can incorporate the expected performance of these units in their studies.

ERCOT agrees with the SDT’s overall approach of ensuring that PRC-029 is clearly a performance-based standard. However, the standard is not entirely clear on this point, as the Time Horizon is “operations assessment” instead of “Real-time Operations.” Additionally, the standard generally uses a structure of ‘owners…shall… ensure that’ instead of an ‘owners….shall.. perform’ structure. Structures found in other standards, such as BAL-001’s ‘entity…shall.. operate such that…’ structure or BAL-001-TRE’s ‘entity….shall….meet (or exceed)’ structure may also work well for PRC-029.

ERCOT notes that FERC Order 901 states, “we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system disturbances and that permit IBR tripping **only to protect the IBR equipment** in scenarios similar to when synchronous generation resources use tripping as protection from internal faults. The new or modified Reliability Standards must require registered IBRs to continue to inject current and perform frequency support during a Bulk-Power System disturbance” (emphasis added). To meet this directive, it may be important to clearly specify that partial failures (individual IBR unit trips or abnormal responses) also fall under PRC-029.

ERCOT therefore recommends modifying the Purpose statement for PRC-029 as follows: “To ensure that Inverter-Based Resources**, and their IBR Units,** remain connected and perform operationally as expected to support the Bulk-Power System during and after defined frequency and voltage excursions.”

The figures in Attachments 1, 2, and 3 appear to be intended to be graphical representations of the tables. To that extent, they are redundant (and potentially contradict what is in the tables). They may be valuable in visualizing the requirements, but they are also ambiguous in that the lines are not precisely defined, and it is not clear if ride-through is required on the lines themselves. ERCOT recommends that these figures be moved to the Technical Rationale or that Attachments 1, 2, and 3 include a clarification that the plots are for visualization purposes only and that the tables define what is actually enforceable

Item 7 in Attachment 1 should not imply that the IBR shall trip beyond the minimum duration. While the inclusion of the term "minimum" helps clarify item 7, the "shall not trip until…" language implies that the IBR shall trip once the minimum ride-through time duration has elapsed.

SDT's proposed language:

"At any given voltage value, each IBR shall not trip until the time duration at that voltage exceeds the specified minimum ride-through time duration. If the voltage is continuously varying over time, it is necessary to add the duration within each band of Tables 1 and 2 over the 10-second time period to determine compliance."

ERCOT's proposed language:

"The IBR shall ride through voltage conditions beyond those specified in Tables 1 and 2 above to the maximum extent the equipment allows. If the voltage is continuously varying over time, it is necessary to add the duration within each band of Tables 1 and 2 over the 10-second time period to determine compliance."

Similar wording should also be applied in item 3 of Attachment 2 and item 4 of Attachment 3.

ERCOT is concerned that item 10 in Attachment 1 ("If the positive sequence voltage at the high-side of the main power transformer enters the Permissive Operation Region, an IBR may operate in current block mode if necessary to protect the equipment") is inconsistent with the following directive from paragraph 190 of FERC Order 901 (as cited in the technical rationale): "Any new or modified Reliability Standard must also require registered IBR generator owners and operators to prohibit momentary cessation in the no-trip zone during disturbances."

The proposed defined terms do not seem to be appropriate for the NERC glossary, especially if they are intended to be used exclusively for IBRs. If the SDT keeps these proposed terms, the definitions should be improved to include durations in addition to voltage ranges and to note that they are only valid for application to IBRs. Furthermore, there are inconstancies between these terms and Tables 1 and 2 in Attachment 1. For example, the Continuous Operating Region is defined as 0.9-1.1 pu (inclusive), but the tables specify only a one second ride-through time for 1.1pu voltage and an 1800 second ride-through time for voltages greater than or equal to 1.05pu, which is not consistent with the concept of continuous operations. Additionally, the terms are used inconsistently in PRC-029, as the terms are defined as "Operating Regions," but frequently appear in PRC-029 as "Operation Regions."

The Technical Rationale includes the following language:

"The proposed PRC-029 must be understood as an event-based standard. Compliance with PRC-029 is determined from IBR ride-through performance during transmission system events in the field and not from interconnection studies, transmission planning studies, operational planning studies, or from IBR models."

ERCOT recommends that the SDT add basic expectations to the Technical Rationale instead of simply stating that compliance is not determined by studies. For example, GOs should design and/or test their facilities to help ensure they won't be non-compliant during an actual event. Furthermore, it would be helpful to offer advice or SDT opinions on how ride-through should be evaluated during design, interconnection, planning, and operational studies. Even though deficient performance in such studies may not be a violation of PRC-029, it makes little sense to proceed with or allow an interconnection of a plant whose simulation models indicate that it will be unable to comply with PRC-029. Such guidance in the Technical Rationale would be beneficial for industry even if the Requirements in the standard do not contain a corresponding mandate.

The Technical Rationale should describe the basis for the "6-second frequency ride-through capability requirement for frequencies in the ranges of 61.8Hz to 64Hz or 57.0Hz to 56.0Hz range," as it is unclear why this approach was chosen instead of an approach that goes all the way up to 65 Hz and down to 55 Hz for 10 seconds or only up to 63.5 Hz and down to 56.5 Hz for 5 seconds.

It is also unclear how the SDT addressed the phase lock loop (PLL) loss of synchronism concerns discussed in FERC Order 901. While there is certainly an interrelationship, certain protection systems like PLL loss of synch may not need to be enabled. Even if enabled, these systems may, if not correctly configured, require additional tuning to ensure the PLL circuit properly controls and prevents some of the other parameters from tripping the unit offline (e.g. phase angle, RoCoF, and overvoltage). The SDT should consider adding additional language to PRC-029 to clarify that phase lock loss of synchronism trips (whether directly or indirectly involved) are not allowed.

The SDT should also consider adding the following items to Attachment 1 for clarity:

11. To the extent possible, IBRs should not use these curves as the absolute voltage or frequency protection set points but should strive to exceed them up to their equipment capabilities while still ensuring adequate equipment protection.

12. IBRs are not required to trip when voltage and frequency are in the may-trip or permissive operation regions.

Additionally, ERCOT has overall concerns with the work plan pushing the planner and operator requirement changes to the final phases. FERC Order 901 states, "To the extent NERC determines that a limited and documented exemption for those registered IBRs currently in operation and unable to meet voltage ride-through requirements is appropriate due to their inability to modify their coordinated protection and control settings, we direct NERC to develop new or modified Reliability Standards to mitigate the reliability impacts to the Bulk-Power System of such an exemption. As NERC will consider the reliability impacts to the Bulk-Power System caused by an such [sic] exemption, we believe that the concerns raised by NYSRC and Indicated Trade Associations on the appropriate registered entity responsible for implementing the mitigation activities, and the nature of such mitigation, should be addressed in the NERC standards development process."

Due to the interrelationship between these factors, the allowance for limited exemptions should be linked to the need to mitigate the impact of such exemptions, which will take time in and of itself. In addition, Order 901 directs NERC to consider the reliability impacts of such an exemption. If the SDT does not have identified quantities or models of likely exemptions to assess the impact of allowing exemptions, it is unclear how NERC is considering the reliability impacts of allowing exemptions. There must be guardrails in place to ensure that exemptions are truly limited, not open-ended, and there should be verification by means of accurate models and studies that the system can withstand the impacts of exemptions. If such studies demonstrate unreliable operations (i.e. Instability, Cascading Outages, and uncontrolled separation) would result from granting exemptions, then the exemptions should not be accepted. While ERCOT understands the impacts to generator owners, such assessment and determination should be made under FERC's direction to ensure that the limited exemptions and risk posed by such exemptions are balanced in such a way that the system maintains Reliable Operation.

Finally, regarding the implementation plan, ERCOT does not agree with how the FERC Order 901 excerpt quoted under "Equipment Limitations and Process for Requirement R6" has been applied. The FERC Order 901 excerpt refers to "typically older IBR technology," which would exclude a majority of IBRs that are in operation today. Aligning eligibility for PRC-029-1 exemptions based on documented equipment limitations under Requirement R6 with the effective date of PRC-029-1 would allow potentially hundreds of GWs of newer IBRs to qualify for exemptions. Such an allowance could result in a failure to realize the reliability benefits FERC intended to capture, as it would allow legacy IBRs to claim exemptions even if they are ultimately capable of complying with the requirements of PRC-029. Unless there is assurance, based on validated and accurate models, that planners and operators can verify that the System can withstand the impact of allowing these exemptions, this allowing this level of potential exemptions may not allow for Reliable Operations. In such instances where exemptions may not allow for Reliable Operations, there should be additional evaluation of available physical modifications (e.g. upgrade kits, new power plant controllers, new controller cards/circuits, control communication networks, component upgrades) for IBR technology that is not approaching its end of life and or an upcoming replacement/refurbishment cycle like "typically older IBR technology" is. Additionally, IBRs that make physical modifications to achieve compliance or that have to make software changes at multiple sites may need additional implementation time when such changes require changes at each individual inverter or turbine.

ERCOT expresses appreciation for all of the SDT's hard work in meeting an expedited timeline for developing a technically complex set of Requirements that attempts to balance elements from IEEE 2800, FERC Orders, NERC recommendations, and vast amounts of stakeholder input. The SDT is to be commended for its progress thus far on this critical standard.

Likes 0	
Dislikes 0	

Response

Thank you for your comments

Type 1 and Type 2 Wind: The team agrees and has added these resources into PRC-024-4 applicability. Language throughout the Standard was adjusted to reflect this change.

Capability and Performance Measures: The team agrees and the measures for R1 through R3 have been adjusted to include design/capability based requirements as well as the demonstration of performance during disturbances.

Time Horizon: The team finds that the Operational Assessment selection is appropriate. Real-time Operations is defined as “actions required within one hour or less to preserve the reliability of the bulk electric system”. In the event of Ride-through, no actions are taken by an operator in requirement language.

Note 5 (previous Note 4): The team finds that the per unit value should be left to the PC/TP. That approach is consistent with PRC-024-4.

Partial Failures and “IBR Unit”: The team would point to the PRC-030 draft that would analyze voltage/frequency excursions and identify if partial plant performance would necessitate a Corrective Action Plan. PRC-029 is only applicable to the overall plant/facility.

Attachment 1: Tables and Figures in Attachment 1 have been revised to add clarity on the operation regions. The range of values in row #4 of Tables 1 and 2 to clarify the continuous operation region. The team believes the figures provide additional clarity and complement the tables.

Shall not trip until…: The team agrees and has modified the notes in Attachment 1 and Attachment 2 (previous attachment 3) to “shall Ride-through unless… has been exceeded…”.

R2: The team added requirement subpart 2.3 to provide clarity on the operation within the Permissive Operation Region.

Terminology: The team has removed the definitions for operating regions. Language within the requirements and the attachments have been revised to reflect this.

Evaluation of Studies: clarity on capability expectations as well as performance have been added to the requirements and measures.

Previous R5: Previous Requirement R5 has been removed and added as an exemption to Requirement R1.

Frequency Values: The team selected these values to reflect the system need and to align with IEEE 2800 -when possible- and to accommodate ride-through frequency requirements in PRC-024 for synchronous machines and Type 1 and 2 wind.

PLL loss of synchronism: A footnote has been added to R1 to clarify PLL loss of synchronism

Attachment 1 – Clarification: Note 12 has been added to clarify the zones.

Regarding Exemptions: The team has modified Requirement R4 (previous R6) to include clarity on allowable exemptions and requires identification of such limitations to be documented and submitted.

Shonda McCain - Omaha Public Power District - 6

Answer	
Document Name	

Comment	
OPPD supports comments provided by GRE: Michael Brytowski, Great River Energy, 3, 4/17/2024	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to Great River Energy.	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	
Document Name	
Comment	
For PRC-029-1 PG&E asks the SDT the following question: Does Table 1 or 2 apply to Type 4 Wind IBRs? It is unclear which table it would apply to and should be clarified since Table 1 specifies “Wind IBR” but not which types of Wind IBRs. PG&E suggests reconsidering the use of the term “trip” or “no-trip.” Per IEEE 2800-22, “trip” for IBRs may not mean the same as has been traditionally used for synchronous machines and other electric elements. For PRC-024-4 PG&E has the following question for the SDT to clarify: For Transmission Owners, does new language in sections 4.1.2 & 4.2.2 only apply to Synchronous Condensers?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	

Attachment 1 – Type 1 and Type 2 wind: Additional language was added to a new footnote 10 and adjustments were made to Note 1 to clarify.
Terminology- Ride-through: The team agrees and has defined a new term for Ride-through and replaced language the requirements with this new term. Attachments have also been updated to utilize this term as the "Must Ride-through Zone".
Synchronous Condensers: The applicability section has been modified to apply to synchronous condensers, their step-up transformers, and auxiliary transformers.

Richard Vendetti - NextEra Energy - 5	
Answer	
Document Name	
Comment	

NextEra aligns with EEI's comments:

PRC-029-1 (Applicability Section) Comments: EEI does not support the Applicability Section of PRC-029-1 for the following reasons:

{C}1. Applicability details should not be contained in footnotes. Please remove footnote 1 from the Applicability Section.

{C}2. Voltage Source Converter – High-voltage Direct Current (VSC-HVDC) are not defined or justified within the Technical Rationale as to why these resources need to be added PRC-029.

{C}3. Without a justification of a need to include VSC-HVDC systems, TOs should be removed from PRC-029-1.

{C}4. EEI does not support the use of the term "BPS IBRs" because no such term exists in the NERC Glossary of Terms that might provide entities with the knowledge to know definitively which IBRs are applicable.

{C}5. EEI also does not support language that points to the registration criteria.

To address our concerns, we suggest the following changes to the Applicability Section of PRC-029-1, noting the Facilities portion of our comments utilize the recommendations from the Project 2020-06 SDT (see boldface changes below):

{C}**4. Applicability:**

{C}4.1 Functional Entities:

{C}4.1.1 Generator Owner

{C}**4.1.2** {C}**Transmission Owner (and footnote 1)**

{C}4.2 Facilities: **(1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. For purposes of this standard, the term "applicable Inverter-Based Resource" or "applicable Inverter-Based Resources" refers to the following:**

{C}**4.2.1** {C}**BPS IBRs**

{C}**4.2.2** {C}**IBR Registration Criteria**

PRC-024 Comments: While there were no questions related to the proposed modifications to PRC-024-4, EEI does not support all of the proposed changes made to PRC-024-4. Note the following:

Applicability Section of PRC-024-4

EEI does not support changing the intent of 4.2.1.4 (Previously 4.2.1.5) to include multiple synchronous generators connecting to a common bus under the BES Definition, Inclusion I4. Since the development of the BES definition, Inclusion I4 did not include or intend to include synchronous generators. Had that been the intent, the SDT could have included synchronous generator resources in I4. Furthermore, the BES Reference Document states in Chapter I4: BES Inclusion the following:

Dispersed power producing resources are small-scale power generation technologies that use a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include, but are not limited to: solar, geothermal, energy storage, flywheels, wind, microturbines, and fuel cells.

While EEI is open to making modifications to the BES Definition, trying to provide interpretations within individual Applicability Sections of proposed NERC Reliability Guidelines is not the proper method to make such a change. For this reason, and since 4.2.1.4 (previously 4.2.1.5) was intended to address IBRs; this part of the Applicability Section of PRC-024-4 should be deleted.

Comments on the proposed New Definitions

EEI has no concerns with the proposed new definitions, but we do have some non-substantive comments on their usage throughout PRC-029, Implementation Plan and Technical Rationale. (See below)

{C}· Usage of the newly defined terms deviated from the defined term within PRC-029 and the Technical Rational. (i.e., Operating vs. Operations)

{C}· Incorrectly stating in the Implementation Plan that there were no newly defined terms. Please correct this error.

Continuous Operating Region – Only used once in Requirement 2.3.

{C}· Continuous Operation Region used in Requirements 2.1, 2.1.2, 2.4, & once in Attachment 1 (i.e., suggest changing the defined term to Continuous **Operation** Region or correct to Continuous **Operating** Region throughout)

{C}· Continuous Operation Region used twice in the Technical Rationale; Continuous Operating Region never used in the Technical Rationale.

Mandatory Operating Region – Never used in PRC-029

{C}· Mandatory Operation Region used in PRC-029 in Requirements 2.2, 2.3, 2.4 & once in Attachment 1 (i.e., suggest changing the defined term to Mandatory **Operation** Region or correct to Mandatory **Operating** Region throughout)

{C}· Mandatory Operation Region was used twice in Technical Rationale; Mandatory Operating Region was never used in the Technical Rational.

Permissive Operating Region – Never used in PRC-029

{C}· Permissive Operation Region used in PRC-029 in Requirements 2.3, 2.4, & used twice in Attachment 1 (i.e., suggest changing the defined term to Permissive **Operation** Region or correct to Permissive **Operating** Region throughout)

{C}· Permissive Operation Region used once in the Technical Rationale; Permissive Operating Region never used in the Technical Rationale.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
Applicability footnotes: The usage of footnotes in the applicability section is often used to provide clarity and is consistent with usage in PRC-024-4.
VSC-HVDC: Modifications have been made to include these elements within PRC-029.
Applicability: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.

Operation Region: The team agrees and has removed the operation regions as defined terms.
Attachment 1: Tables and Figures in Attachment 1 have been revised to add clarity on the operation regions.

Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

Has the MPT Volts/Hz capability been considered when considering the high voltage/low frequency curves?

For R6, the use of "repair" seems inappropriate - an equipment limitation is not equivalent to a broken part in need of repair. We suggest that "repair(s) or replace the limiting element" in R6.1.4 and R6.2 be changed to "remedy the equipment limitation".

The standard requires IBR to ride-through regardless of operating condition of the transmission system. The IBR is typically designed to ride-through for planning events, most likely defined in TPL-001 standard. Considering 24 hour/365 day operation, the transmission system may be experiencing outages beyond planning events. During such an abnormal operating condition, the IBR may not be able ride-through system disturbances as specified. The same could also be true as the transmission system changes over time, as new transmission lines are added to the transmission system and generating plants are added to or removed from the transmission system. The IBR which is designed to ride-through certain transmission network and operating conditions at the time of entering commercial operation may not be able to do so if transmission network and operating conditions change significantly over time. The standard needs to recognize such issues and grant an exception if IBR fails to ride-through.

The SDT proposes to add continuous operating region, mandatory operating region, and permissive operating region terms to the Glossary of Terms. However, these terms are specific to voltage ride-through requirements. There is no reason to limit those terms to voltage ride-through capability only. The continuous and mandatory operation region terms could be applied to frequency ride-through capability as well. Refer to IEEE 2800 to see how these terms are used for both voltage and frequency ride-through capabilities.

Continuous/mandatory/permissive operating region terms:

1. The SDT uses continuous/mandatory/permissive “operating” region as well as continuous/mandatory/permissive “operation” region. Be consistent with either “operating” or “operation” throughout the standard.
2. Following comments to align voltage ranges in Attachment 1, Tables 1 & 2:
    - Mandatory Operating Region term should read like following: The range of voltages, measured at the high-side of main power transformer, that are ≥ 0.1 per unit and < 0.9 per unit OR > 1.1 per unit and ≤ 1.2 per unit.

- Permissive Operating Region term should read like the following: The range of voltages, measured at the high-side of main power transformer, that is ≤< 0.1 per unit.

3. These terms specify voltage threshold, but which voltage is used in these terms is in the Attachment 1. Per attachment 1, the continuous and mandatory operating regions are based on phase-to-ground or phase-to-phase voltages. But the permissive operating region is based on positive-sequence voltage. The defined terms should also make it clear which voltage thresholds are defined.

Consider revising the purpose statement as following: To ensure that Inverter-Based Resources (IBRs) remain connected and support the Bulk Power System (BPS) during and after frequency and voltage excursions events.

Transmission Owner is included as a Functional Entity in section 4. However, footnote 1 makes it confusing. Would standard only apply to Transmission Owner when it owns the VSC-HVDC transmission facility connecting isolated IBR with BPS?

Currently, PRC-029-1 allows for a GO or TO to seek an exemption from meeting voltage-ride through requirements in R1 and R2.

Southern Company believes that GOs and TOs should be able to seek exemptions from meeting frequency and voltage ride-through requirements in R1 – R5.

The proposed standard only provides for VRT exemptions. Any consideration for FRT, ROCOF, phase angle?

Comment to PRC-024-4:

Facilities section 4.2.1.1 should include I2 of the BES definition and section 4.2.1.4 be removed or reference I2 in place of I4. I4 of the BES definition was intended to point to IBRs at the time of the latest BES definition adoption in 2018 as dispersed power resources and was not intended to point to synchronous generation resources.

Opportunity to clarify that legacy IBRs must maximize capabilities:

1. For NOGRR245, it has been advocated that legacy IBRs should make software / settings changes to maximize capabilities to meet or approach the new ride-through requirements, unless such changes are unreasonably priced.
2. Southern's experience is that software / settings changes are commercially reasonable. The "unreasonably priced" language is intended to protect against price gauging from OEMs.
3. The current PRC-029-1 draft requires legacy IBRs to meet the new voltage ride-through requirements unless a documented technical limitation exists. So a legacy IBR can document an exemption and have performance capabilities less than new VRT standard. But what happens if that legacy IBR owner later learns there is an available software / setting change that would reduce or remove the limitation? The current draft need clarity to address this.

4. Southern Company supports such a software / setting deployment requirement and believes it would (1) be commercially reasonable and (2) more clearly require ride-through capability maximization.

Finally, Southern Company supports EEI and NAGF comments.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
Voltz/Hz Capability: The team agrees this capability needed clarity and have included this as a potential exemption to voltage Ride-through requirement R1.
Removing Limitations: The team agrees that replacing equipment associated with the limitation also remove any exemption. This has been clarified in Requirement R4 (previous R6).
Scope of legacy IBR and approach by the team: The scope of PRC-029 is consistent with the SAR assigned to this team and the regulatory directives from FERC Order No. 901 that were assigned to this team. There is some potential for documented limitations within Requirement R4 and the Implementation Plan for legacy equipment that cannot meet any voltage ride-through requirements (R1 and R2). Some revisions were made to clarify design capabilities would still be required.
Terminology and Attachment 1: The team agrees and has removed the terms for operating regions from the list of defined terms and the requirements. Attachment 1 has been modified to add clarity for the operating conditions for each of the regions referenced in the tables.
Purpose statement: The team agrees and has modified the purpose statement.
Transmission Owner: Correct, the current version of the draft would apply to VSC-HVDCs with a dedicated IBR connection that is owned by the TO.
Exemptions: The scope of allowable exemptions within R4 (previously R6) is consistent with the regulatory directives of Order No. 901. Frequency or phase-jump requirements cannot apply for exemption. New IBR cannot apply for exemption. This is consistent with the ordered directives.
Regarding Excemptions: The team has modified Requirement R4 (previous R6) to include clarity on allowable exemptions and requires identification of such limitations to be documented and submitted.
PRC-024 and PRC-029 applicability: The applicability sections have been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from these draft.

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer	

Document Name	
Comment	

While inclusive, is PRC-024-4 Facility Section Part 4.2.1.4 applicable to synchronous generators? Inclusion 4, when written, was designed to catch the wind/solar aspects of the generation fleet. Inclusion 2 seems to be more appropriate (if not already covered in 4.2.1.1). The MPT footnote appears to be limited to Quebec TO synchronous generators and does not include a reference to synchronous condensers (4.2.2 synchronous condenser applicable facilities simply says “step-up transformer(s)”). In PRC-024-4 Requirement 2 there is a reference to “MPT” and the introduction of Transmission Owner within Requirement. It is not clear if applicable to TOs outside of Quebec based on the language provided (from Requirement R2---“…a voltage excursion at the high-side of the GSU or MPT…” which the GSU/MPT is not mentioned in applicable Facilities for synchronous condensers Section 4.2.2). In Attachment 1 there is a similar issue in that footnote 8 on page 21 mentions the high-side of the GSU or MPT—Also should be noted that Footnote 8 does not appear to have an anchor (location within document to reference the footnote). On page 22 of Attachment 2A there are references to the GSU/MPT as well. Just seeking clarification to avoid an entity having a synchronous condenser indicating no applicability because of the language. This inconsistency in language does not appear to follow items 8 (“Clear Language”) and 10 (“Consistent Terminology”) of the Ten Benchmarks of an Excellent Reliability Standard as referenced in the Guideline for Quality Review of NERC Reliability Standards Project Documents.

PRC-029-1- SDTs need to use the same IBR terms and not add additional descriptors. Even the title of the Standard is not consistent. Should use the proposed definitions in 2020-06 Verifications of Models and Data for Generators for clarity and consistency. There is no such Facility as “IBR Registration Criteria”. Footnote 1 contains undefined terms which should be defined within this Standard if used. Because of the inconsistency in definition use, it is not clear whether this applies to the IBR or IBR Unit locations (even when stated that it does not apply to “individual inverter units or measurements takes at individual inverter unit terminals.” If looking at Project 2020-06, the inverters in a “common IBR Unit configuration’ as shown in Figure 2.2 and 2.3 of the Technical Rational are exactly at the individual IBR Units (see link 2020-06_IBR_Definitions_Technical_Rationale_02222024.pdf (nerc.com)). Is “exchange current” considered the same as “inject current” which is used (various ways) in other Standards being proposed? The new terms introduced address range of voltages that may not correlate to the Tables effectively. The Continuous Operating Region definition shows to **include** 1.1 per unit and should reflect the 1800 seconds in Table 1 and Table 2 but the 1.1 voltage per unit in the Tables show only a 1 second capability (Mathemataical expression includes 1.1 per unit in the Table which it should not). Furthermore the 1.2 voltage per unit is shown to be included in the Mandatory Operating Region but NOT in the Tables. Please clarify the expectations as entities had an issue in PRC-024 setting protection on the curves when initially mandatory. With conflicting information, and Figures that are not as explicit or appear to match the Tables, WECC is concerned there may be confusion. This language does not appear to follow Item 8 (“Clear Language”) and 10 of the Ten Benchmarks of an Excellent Reliability Standard as referenced in the Guideline for Quality Review of NERC Reliability Standards Project Documents.

At a minimum, bullet 2 under Attachment 1 Table 2 should mention all the types of IBR as listed in other Standards (Type 3 and type 4 of wind is covered in bullet 1, “Isolated IBR” is undefined, and 2.b. simply says “Other IBR plants” and limits hybrid to PV and “ESS” (possible typo that

should be "BESS"?). The "not limited to" should remain and the SDT may say all are covered with said language but clarity could be provided by adding consistent language as used in other Standards. This inconsistency in language does not appear to follow items 10 ("Consistent Terminology") of the Ten Benchmarks of an Excellent Reliability Standard as referenced in the Guideline for Quality Review of NERC Reliability Standards Project Documents. Attachment 1 Table 2 Bullet 3 leaves the applicability to the TP but the TP is not called out as an applicable entity and this is an Operations Assessment time horizon. In the Technical Rationale it clearly states "*Compliance with PRC-029 is determined from IBR ride-through performance during transmission system events in the field and not from* ***interconnection studies, transmission planning studies****, operational planning studies, or from IBR models*." So, if IBRs in a hybrid plant have issues, the TP is to blame for calling out the incorrect Table? TPs may very well have the studies to determine how long a ride-through should be sustained by IBRs, but there is no compliance responsibility (not saying there should be—should be responsibility properly assigned through the Standards process). Bullet 4 allows the PC or TP to change the Requirement criteria but there is no accountability if done (furthermore no notifications for awareness to those entities in the Operations side of business). The apparent responsibility does not appear to follow items 1 ("Applicability") of the Ten Benchmarks of an Excellent Reliability Standard as referenced in the Guideline for Quality Review of NERC Reliability Standards Project Documents. "MPT" is not defined in the Standard yet used repeatedly. Clarity can be provided with a footnote or addition of a definition (not that synchronous condenser use in PRC-024-4 was unclear for MPT). There are only Severe VSLs for Requirements R1 through R5. Clarity on where the inverter is (based on the 2020-06 drawings provided and language in this Standards Technical Rational) will be important to understand. Failure of individual IBR units (as defined in 2020-06) appears to not be addressed9unless it is intended to be addressed by the Sever VSL) and will have an impact on being complaint at the IBR level.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **PRC-024 applicability and MPTs:** The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft. Additionally, the footnotes have been modified to add clarity regarding the MPT. **PRC-029 applicability:** The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.	

Terminology and Attachment 1: The team agrees and has removed the terms for operating regions from the list of defined terms and the requirements. Attachment 1 has been modified to add clarity for the operating conditions for each of the regions referenced in the tables. Further, the notes have been revised to resolve issues identified above. **VSL tables:** The tables have been revised to include additional levels per the capability-based requirement language.	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
Carey Salisbury - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	
Document Name	

Comment	
For each of the measures M1-M5, what “other evidence” can demonstrate compliance with R1-R5 other than recorded data? How does the drafting team believe that generator owners can assure this performance expectation can be achieved prior to an actual event? There is no test verification that can be performed to confirm the expected performance that considers every type of system disturbance that can occur.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Capability and Performance Measures**: The team agrees and the measures for R1 through R3 have been adjusted to include design/capability based requirements as well as the demonstration of performance during disturbances.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
Many references in the requirements point toward Continuous Operating Region, Mandatory Operating Region, and Permissive Operating Region "as specified in **Attachment 1**", yet Attachment 1 does not specify any of these regions. Operating Regions should be added to Attachment 1 tables and figures. No-trip zone Figures 1 & 2 don't match the tables. Is there a point or distinction being made by using capitalized "Systen" instead of undefined "system" in requirements?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Attachment 1:** Tables and Figures in Attachment 1 have been revised to add clarity on the operation regions. The range of values in row #4 of Tables 1 and 2 to clarify the continuous operation region.	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	

The Implementation Plan should be extended to 36 months to allow for monitoring equipment to be installed at sites completed before PRC-029 becomes enforceable, to demonstrate performance and compliance with the standard.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
The implementation of PRC-029 is set to follow PRC-028's implementation plan. All of the revisions to Standards to address Order 901 must be fully implemented no later than 2030.

Dave Krueger - SERC Reliability Corporation - 10	
Answer	
Document Name	
Comment	

On behalf of the SERC Generator Working Group:

Consider allowing for some period of time beyond the effective date of PRC-029 to document limitations per (R6) – contemplate the real impact to BES reliability of limitation documentation.

Consider synchronizing the phase in of PRC-028 with the measures such as M1 stating "*shall have evidence of actual recorded data*...".

For each of the measures M1-M5, what "other evidence" can demonstrate compliance with R1-R5 other than recorded data? How does the drafting team believe that generator owners can assure this performance expectation can be achieved prior to an actual event? There is no test verification that can be performed to confirm the expected performance that considers every type of system disturbance that can occur.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Implementation Plan: The implementation of PRC-029 is set to follow PRC-028's implementation plan. All of the revisions to Standards to address Order 901 must be fully implemented no later than 2030.
Measures - data: The compliance measures for demonstration of performance were revised from "actual recorded data" to "actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data".
Capability and Performance Measures: The team agrees and the measures for R1 through R3 have been adjusted to include design/capability based requirements as well as the demonstration of performance during disturbances.

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	
Document Name	

Comment

OPG supports IESO, HQ, and NPCC Regional Standards Committee's comments.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. See response to IESO, HQ, and NPCC Regional Standards Committee.

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment

MP agrees with the NSRF's suggestions to enhance PRC-029, especially regarding limiting the power of equipment limitations from exempting applicable entities from compliance, expanding the applicable facilities to include IBRs of 20MVA and above, and more precisely defining applicable entities and facilities within the text of the standard. MP also suggests that a formal definition of "Inverter-Based Resources" precede the adoption of the standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to NSRF. The team will incorporate changes to the applicability section and usage of IBR defined terms as those are finalized.	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	
Document Name	
Comment	
We are concerned that the standard refers to a defined term for IBR which has yet to be adopted in project 2020-06. We suggest that the drafting team ensure consistent language is used in the section 4.2 "Facilities" section with the other projects such as 2021-04 (PRC-028) and 2023-02(PRC-030). Section 4.2.2 refers to IBR Registration criteria, however it is our understanding that section 4.2.1 would refer to GOs and TOs "that own equipment as identified in section 4.2" and where section 4.2 would indicate "the Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV." . We question why "attachment 1" and "Requirement R6" are written in bold. Attachment 1: should the "including, but not limited to" in table 2 include the same list (or minimally the same wording) that is found in the technical rationale of the IBR definition in project 2020-0?. For example, the IBR list in 2020-06 refers to "solar photovoltaic" whereas table 2 refers to "photovoltaic (PV)".	

In what standard does the PC/TP define the applicable table in point 3 of section 2 in attachment 1? Same question for the voltage base for per unit calculation in both Attachment 1 and 2. Is there a corresponding requirement in another standard that requires the PC/TP to do this?

· Terms : Mandatory and permissive operation should be defined based on the attachment figures allowing for interconnections to use different requirements

· A-4.2.2 What is the IBR registration criteria? Add a clear reference and make sur the user understands what the IBR registration criteria is.

· B-R2-2.1 Attachment 1 only uses "no-trip zone". Define continuous operating region more clearly in the table (similar to what is done in PRC-024-4)

· B-R2-2.1.2 Can the TP ask for a mix of active/reactive power based on a predetermined ratio (currently only indicated as active or reactive).

· B-R2-2.2 Attachment 1 only uses "no-trip zone". Define "mandatory operation region" in Attachment 1.

· B-R2-2.4 Permissive operation region is not used or defined in attachment 1.

· B-R3. The document refers to an overvoltage value of 1.2pu. It should refer to a voltage exceeding the mandatory operating region in order for Interconnections to set their own overvoltage table.

· B-R3. Since R6 does not apply to this requirement, what will be done with existing IBR that cannot ride through these overvoltages ? An exemption clause is required for existing IBR that cannot be modified or upgraded.

· B-R4. The 5Hz/s value should be moved to Attachment 3 and B-R4 should only refer to the value in the Attachment.

· B-R4. Since R6 does not apply to this requirement, what will be done with existing IBR that cannot ride through these frequencies and ROCOF ? (for instance, for all the HQ connected projects, the ROCOF requirement was 4Hz/s) An exemption clause is required for existing IBR that cannot be modified or upgraded.

· B-R5. Since R6 does not apply to this requirement, what will be done with existing IBR that cannot ride through this phase angle jump ? An exemption clause is required for existing IBR that cannot be modified or upgraded.

· Attachment 1. Tables 1 and 2: Indicate what is considered as “continuous operation”, “mandatory operation” and “permissive operation” in an additional column.

· Attachment 1. HQ needs a Quebec regional variance since the Québec Interconnection has its own requirements in this regard.

· Attachment 2. Bullet 3: This sentence is hard to read. Proposed replacement: "Each IBR shall not trip unless the cumulative time of one or more instances in which the instantaneous voltage exceeds the respective voltage threshold over a 1-minute time window exceeds the minimum ride-through time" · Attachment 2. HQ needs a Quebec regional variance since the Québec Interconnection has its own requirements in this regard. · Attachment 3. This attachment should also include the maximum absolute ROCOF value. · Attachment 3. HQ needs a Quebec regional variance (or the equivalent through the “regie de l’energie” approval process). · B-R2-2.1.2 Which entity between Transmission Planner, Planning Coordinator, Reliability Coordinator and Transmission Operator has priority to specify those requirements? · B-R2-2.4 Which entity between Transmission Planner, Planning Coordinator, Reliability Coordinator and Transmission Operator has priority to specify those requirements?

Likes 0	
Dislikes 0	

Response
Thank you for your comment. **IBR:** The team agrees and will include IBR defined terms once those are approved. **Applicability section:** The team agrees and has collaborated with PRC-028 and PRC-030 teams for consistent language in the applicability section. **Attachment 1:** These notes have been modified to clarify usage of the tables. **Attachment 1**: Tables and Figures in Attachment 1 have been revised to add clarity on the operation regions and the “must Ride-through zone”. The range of values in row #4 of Tables 1 and 2 to clarify the continuous operation region. **Applicability**: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft. **Transient Overvoltage**: Previous requirement R3 and Previous Attachment 2 have been removed. **Frequency 5hz clarification**: The team has made modifications to the requirement language and the attachment to address this. **Regarding Excemptions**: The scope of allowable exemptions within R4 (previously R6) is consistent with the regulatory directives of Order No. 901. Frequency or phase-jump requirements cannot apply for exemption. New IBR cannot apply for exemption. This is consistent with the

ordered directives.The team has modified Requirement R4 (previous R6) to include clarity on allowable exemptions and requires identification of such limitations to be documented and submitted. **Quebec variant**: The team will coordinate with Hydro Quebec to include their variant as identified by Hydro Quebec. Priority: This issue is out of scope for the team. The language in the requirement is to make allowance for established operational instructions.	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
The implementation plan is also very aggressive and for some generators may be impossible to meet. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. All revisions to Reliability Standards directed by Order 901 must be fully implemented by 2030.	
Maozhong Gong - GE - GE Wind - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
Overall comments: 1. Implementation date: 6 months is not sufficient for IBR manufacturers to meet the new standard. Instead we propose 2yrs to accommodate product development/adequacy and appropriate validation. 2. For R6, R3,R4,R5 should be included as well for the documented limitation communication (see R6 comments below).	

3. For Attachment 1, for VSC-HVDC connected IBRs, it is not clear if Table 2 is applicable at the MPT on grid side or on the IBR side of HVDC (see Attachment 1 comments below)

4. For MFRT, GEV suggests to align to IEEE2800-2022 7.2.2.4 for consistency (see Attachment 1 comments below).

GEV comments to R6: The language in R6 only allows documented limitations for Requirements R1 and R2. The standard must allow for documentation of limitations for Requirements R3, R4, and R5, as some existing site equipment was not designed to these requirements originally.

GEV comments to Table 2 in Attachment 1: For VSC-HVDC connected IBRs, please clarify if Table 2 is applicable at the MPT on grid side or on the IBR side.

GEV comments to MFRT: For MFRT requirements, GE Vernova strongly suggests that this language should align to IEEE2800-2022 7.2.2.4. Exceptions from the IEEE standard that are relevant were not included, making these requirements inconsistent with 2800-2022.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
All revisions to Reliability Standards directed by Order 901 must be fully implemented by 2030.
The scope of allowable exemptions within R4 (previously R6) is consistent with the regulatory directives of Order No. 901. Frequency or phase-jump requirements cannot apply for exemption. New IBR cannot apply for exemption. This is consistent with the ordered directives.
VSC-HVDC: Language has been added to identify the point of measurement for VSC-HVDC**.**
IEEE: Requirements within the NERC PRC-029 address the scope of the SAR and draw from IEEE2800 but are mandatory and enforceable requirements; in contrast to IEEE2800.

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	
Document Name	
Comment	
PRC-24-4 mentined BPS in the Purpose section. We believe it is typo becuase the rest of the standard the applicabilty is for BES elements. The implemetation plan to to strict to allow cost effect implementation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Applicability**: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR (for prc-024 this will include type 1 and type 2 wind) that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft. **Implementation Plan**: All revisions to Reliability Standards directed by Order 901 must be fully implemented by 2030.	
Imane Mrini - Austin Energy - 6, Group Name Austin Energy	
Answer	
Document Name	
Comment	
AE supports comments provided by Texas RE and the NAGF	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. See response to Texas RE and NAGF.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

EEI offers the following additional comments on both PRC-024 & PRC-029:

PRC-029-1 (Applicability Section) Comments: EEI does not support the Applicability Section of PRC-029-1 for the following reasons:

1. Applicability details should not be contained in footnotes. Please remove footnote 1 from the Applicability Section.
2. Voltage Source Converter – High-voltage Direct Current (VSC-HVDC) are not defined or justified within the Technical Rationale as to why these resources need to be added PRC-029.
3. Without a justification of a need to include VSC-HVDC systems, TOs should be removed from PRC-029-1.
4. EEI does not support the use of the term “BPS IBRs” because no such term exists in the NERC Glossary of Terms that might provide entities with the knowledge to know definitively which IBRs are applicable.
5. EEI also does not support language that points to the registration criteria.

To address our concerns, we suggest the following changes to the Applicability Section of PRC-029-1, noting the Facilities portion of our comments utilize the recommendations from the Project 2020-06 SDT (see removals (i.e., TOs, registration criteria, etc. and other text) and boldface changes below:

4. Applicability:

4.1 Functional Entities:

4.1.1 Generator Owner

Facilities:

(1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

PRC-024 Comments: While there were no questions related to the proposed modifications to PRC-024-4, EEI does not support all of the proposed changes made to PRC-024-4. Note the following:

Applicability Section of PRC-024-4

EEI does not support changing the intent of 4.2.1.4 (Previously 4.2.1.5) to include multiple synchronous generators connecting to a common bus under the BES Definition, Inclusion I4. Since the development of the BES definition, Inclusion I4 did not include or intend to include synchronous generators. Had that been the intent, the SDT could have included synchronous generator resources in I4. Furthermore, the BES Reference Document states in Chapter I4: BES Inclusion the following:

Dispersed power producing resources are small-scale power generation technologies that use a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include, but are not limited to: solar, geothermal, energy storage, flywheels, wind, microturbines, and fuel cells.

While EEI is open to making modifications to the BES Definition, trying to provide interpretations within individual Applicability Sections of proposed NERC Reliability Guidelines is not the proper method to make such a change. For this reason, and since 4.2.1.4 (previously 4.2.1.5) was intended to address IBRs; this part of the Applicability Section of PRC-024-4 should be deleted.

Comments on the proposed New Definitions

EEI has no concerns with the proposed new definitions, but we do have some non-substantive comments on their usage throughout PRC-029, Implementation Plan and Technical Rationale. (See below)

- Usage of the newly defined terms deviated from the defined term within PRC-029 and the Technical Rational. (i.e., Operating vs. Operations)
- Incorrectly stating in the Implementation Plan that there were no newly defined terms. Please correct this error.

Continuous Operating Region – Only used once in Requirement 2.3.

- Continuous Operation Region used in Requirements 2.1, 2.1.2, 2.4, & once in Attachment 1 (i.e., suggest changing the defined term to Continuous **Operation** Region or correct to Continuous **Operating** Region throughout)
- Continuous Operation Region used twice in the Technical Rationale; Continuous Operating Region never used in the Technical Rationale.

Mandatory Operating Region – Never used in PRC-029

- Mandatory Operation Region used in PRC-029 in Requirements 2.2, 2.3, 2.4 & once in Attachment 1 (i.e., suggest changing the defined term to Mandatory **Operation** Region or correct to Mandatory **Operating** Region throughout)
- Mandatory Operation Region was used twice in Technical Rationale; Mandatory Operating Region was never used in the Technical Rational.

Permissive Operating Region – Never used in PRC-029

- Permissive Operation Region used in PRC-029 in Requirements 2.3, 2.4, & used twice in Attachment 1 (i.e., suggest changing the defined term to Permissive **Operation** Region or correct to Permissive **Operating** Region throughout)

- Permissive Operation Region used once in the Technical Rationale; Permissive Operating Region never used in the Technical Rationale.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
Applicability footnotes: The usage of footnotes in the applicability section is often used to provide clarity and is consistent with usage in PRC-024-4.
VSC-HVDC: Modifications have been made to include these elements within PRC-029.
Applicability: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.
Operation Region: The team agrees and has removed the operation regions as defined terms.
Attachment 1: Tables and Figures in Attachment 1 have been revised to add clarity on the operation regions.

Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3

Answer	
Document Name	

Comment

1. Implementation should align with PRC-028-1 proposed implementation to ensure data collecting information is available to adhere to PRC-029-1.

2. PRC-024-4 Applicability and Purpose should include asynchronous type 1 and type 2 wind since these are not IBRs and therefore not applicable to PRC-029:

4.2.1.4 Elements that are designed primarily for the delivery of capacity from the multiple synchronous generators ***or asynchronous type 1 or type 2 wind generators,*** connecting to a common bus identified in the BES Definition, Inclusion I4, to the point where those resources aggregate to greater than 75 MVA.

4.2.1.6 Type I and type II asynchronous wind generation identified in the BES Definition, Inclusion I4.

3. Suggest that the drafting team ensure consistent language is used in the section 4.2 “Facilities” section with the other projects such as Project 2021-04 (PRC-028) and 2023-02(PRC-030). We suggested the following language be included in the applicability section. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
Implementation Plan: The team has revised the implementation plan to follow the effective date of PRC-028.
Type 1 and Type 2 wind: The team agrees and has included these within PRC-024.
Applicability: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	
Document Name	

Comment

Please consider using the risk-based approach when drafting standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy recommends the implementation of EEI and NAGF comments. For clarification, expand the following subparts as stated below: 4.1. Functional Entities: 4.1.1. Transmission Owner that owns equipment as identified in section 4.2. 4.1.2. Generator Owner that owns equipment as identified in section 4.2. 4.2. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment**.**	

Applicability: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
The applicability section should match applicability sections of other IBR standards under development, PRC-030 and PRC-028.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment**.** **Applicability**: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF provides the following additional comments for consideration: *PRC-024:* *a. Section 4.2.1.2 – Consider adding the language "Main Power Transformer (MPT)".*	

b. Section 4.2.1.4 and 4.2.1.5 - Recommend that the proposed language be modified to reference BES Definition – Inclusion I2 instead of Inclusion I4 – Dispersed Power Producing Resources. The proposed new PRC-029 standard's focus is on Frequency and Voltage Ride-through Requirements for Inverter-Based Generating Resources and therefore should include a reference BES I4 resources.

PRC-029:

a. Terms – the NAGF requests additional clarification on how the proposed defined terms work with the proposed PRC-030. Will analysis be required for an event under the proposed PRC-029 and under PRC-030? Potential double jeopardy issue. Alternatively, if tripping is allowed under PRC-029, would an analysis still be required under PR-030?

b. Section 4.2 - Facilities:

i. Use of the capitalized term "Bulk Power System (BPS) Inverter-Based Resources (IBR)" should be reviewed as it is not a defined term in the NERC Glossary of Terms. In addition, it is very likely that not all Bulk Power System Inverter-Based Resources will be registered even under NERC's modified Rules of Procedure. Until the definition of Inverter-Based Resources is approved, the SDT should only use the term "inverter-based resource" if needed.

ii. The NAGF requests clarification if IBR plants that include synchronous condensers should meet the PRC-029 requirements.

c. Comments Related to Attachments:

i. Attachment 1 – Recommend adding to the table a column that species what area is the Continuous Operating Region, Mandatory Operating Region and Permissive Operating Region. As currently structured, it is not clear where the different regions begin or end. If possible, the NAGF recommends a graph showing the different areas for clarity.

ii. The abbreviations "MPT" and "ESS" are not defined within the standard/attachment. Please ensure all acronyms/initializations are fully defined for use.

iii. If the term ESS is intended to mean Energy Storage Systems, does this also apply to water storage systems, or only Battery Energy Storage Systems? If the intent is to refer to Battery Energy Storage Systems, please modify the term used.

iv. Attachment 1, note 3 – There does not appear to be a requirement proposed for the Transmission Planner (TP) to provide direction as stated in note 3. Request clarification on how the TP will provide such guidance/direction on the applicable table to be used.

v. Attachment 1, Note 7 – These notes appear to state that no unit should trip in a 10 second period if voltage is fluctuating, but the summation of time interval does not appear to be 10 seconds in most instances. As an example, assuming that the SDT intends for a generator to follow the voltage for 10 seconds when it is fluctuating between .7 and .5, the unit should be allowed to trip when voltage is below the .5 level

for 1.2 seconds. However, note 7 appears to state that there is a 10 second limit if voltage were to be below .7 for 1 second, then goes below .5 for 3 seconds, then returns to the .7 for 6 seconds. Please verify this interpretation is correct, or how this language should be understood. *vi. Attachment 1, Notes 7 and 8 – Both of these items discuss cumulative numbers in Tables 1 and 2. As worded, it is unclear if the intent is to add the numbers in Table 1 to the numbers in Table 2, or if the intent is to add the numbers in the second column of Table 1 for those resources that are considered Table 1 entities, and similar for Table 2 entities. Please clarify the wording so the intent of the standard is clear.*	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. **MPT**: The team agrees and has modified PRC-024 and PRC-029 to clarify language for the MPT. Thank you for your comment**.** **Applicability**: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft. **Measures (events**): The evidence of compliance for disturbance monitoring that are associated with voltage and frequency excursions that were System disturbances and would be identified for analysis or another trigger by an applicable entity within draft PRC-030. Evidence of disturbance monitoring of IBR associated with those disturbances would be triggered by compliance under the requirements for PRC-030. A GO/TO who provides the data per the requirements in PRC-030 would fulfill the obligations of those requirements. **Operation Region:** The team agrees and has removed the operation regions as defined terms. **Attachment 1**: Tables and Figures in Attachment 1 have been revised to add clarity on the operation regions. **ESS:** This has been revised to BESS **Attachment 1 Notes**: The team has modified notes to address which table should be used. **10 second accumulation:** The team has added clarity to the requirements and TR on how to determine the 10-second window and changing voltages.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	
Document Name	
Comment	

AZPS supports the following comments that were submitted by EEI on behalf of its members:

PRC-029-1 (Applicability Section) Comments: EEI does not support the Applicability Section of PRC-029-1 for the following reasons:

1. Applicability details should not be contained in footnotes. Please remove footnote 1 from the Applicability Section.

2. Voltage Source Converter – High-voltage Direct Current (VSC-HVDC) are not defined or justified within the Technical Rationale as to why these resources need to be added PRC-029.

3. Without a justification of a need to include VSC-HVDC systems, TOs should be removed from PRC-029-1.

4. EEI does not support the use of the term “BPS IBRs” because no such term exists in the NERC Glossary of Terms that might provide entities with the knowledge to know definitively which IBRs are applicable.

5. EEI also does not support language that points to the registration criteria.

To address our concerns, we suggest the following language in the Applicability Section of PRC-029-1, noting the Facilities portion of our comments utilize the recommendations from the Project 2020-06 SDT):

4. Applicability:

4.1 Functional Entities:

4.1.1 Generator Owner

4.2 Facilities: (1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

PRC-024 Comments: While there were no questions related to the proposed modifications to PRC-024-4, EEI does not support all of the proposed changes made to PRC-024-4. Note the following:

Applicability Section of PRC-024-4

EEI does not support changing the intent of 4.2.1.4 (Previously 4.2.1.5) to include multiple synchronous generators connecting to a common bus under the BES Definition, Inclusion I4. Since the development of the BES definition, Inclusion I4 did not include or intend to include synchronous generators. Had that been the intent, the SDT could have included synchronous generator resources in I4. Furthermore, the BES Reference Document states in Chapter I4: BES Inclusion the following:

Dispersed power producing resources are small-scale power generation technologies that use a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include, but are not limited to: solar, geothermal, energy storage, flywheels, wind, microturbines, and fuel cells.

While EEI is open to making modifications to the BES Definition, trying to provide interpretations within individual Applicability Sections of proposed NERC Reliability Guidelines is not the proper method to make such a change. For this reason, and since 4.2.1.4 (previously 4.2.1.5) was intended to address IBRs; this part of the Applicability Section of PRC-024-4 should be deleted.

Comments on the proposed New Definitions

EEI has no concerns with the proposed new definitions, but we do have some non-substantive comments on their usage throughout PRC-029, Implementation Plan and Technical Rationale. (See below)

- Usage of the newly defined terms deviated from the defined term within PRC-029 and the Technical Rational. (i.e., Operating vs. Operations)
  - Incorrectly stating in the Implementation Plan that there were no newly defined terms. Please correct this error.

Continuous Operating Region – Only used once in Requirement 2.3.

- Continuous Operation Region used in Requirements 2.1, 2.1.2, 2.4, & once in Attachment 1 (i.e., suggest changing the defined term to Continuous Operation Region or correct to Continuous Operating Region throughout)
- Continuous Operation Region used twice in the Technical Rationale; Continuous Operating Region never used in the Technical Rationale.

Mandatory Operating Region – Never used in PRC-029

- Mandatory Operation Region used in PRC-029 in Requirements 2.2, 2.3, 2.4 & once in Attachment 1 (i.e., suggest changing the defined term to Mandatory Operation Region or correct to Mandatory Operating Region throughout)
- Mandatory Operation Region was used twice in Technical Rationale; Mandatory Operating Region was never used in the Technical Rational.

Permissive Operating Region – Never used in PRC-029

- Permissive Operation Region used in PRC-029 in Requirements 2.3, 2.4, & used twice in Attachment 1 (i.e., suggest changing the defined term to Permissive Operation Region or correct to Permissive Operating Region throughout)
- Permissive Operation Region used once in the Technical Rationale; Permissive Operating Region never used in the Technical Rationale.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
Applicability footnotes: The usage of footnotes in the applicability section is often used to provide clarity and is consistent with usage in PRC-024-4.
VSC-HVDC: Modifications have been made to include these elements within PRC-029.
Applicability: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.
Operation Region: The team agrees and has removed the operation regions as defined terms.
Attachment 1: Tables and Figures in Attachment 1 have been revised to add clarity on the operation regions.

Joy Brake - Nova Scotia Power Inc. - NA - Not Applicable - NPCC

Answer	
Document Name	

Comment

If using ALL CAPS, consider RCF as the acronym. It is not that significant a metric to require capitalization of “of”.

RoCoF is also used in many other jurisdictions.

FERC order:

“In other words, under certain conditions some IBRs cease to provide power to the Bulk-Power System due to how they are configured and programmed. ” Yes, but PRC-024 now prohibits this. In some cases, settings in the older plants can be tweaked to improve performance but we are having trouble getting good models from the GOs. To address NERC concerns we need requirements for better models.

“some models and simulations incorrectly predict that some IBRs will ride through disturbances, i.e., maintain real power output at pre-disturbance levels and provide voltage and frequency support consistent with Reliability Standard PRC-024-3”. Only if incorrectly modelled.

Require better modelling to identify issues and determine mitigations. PRC-029 will not stop the problem of simulating a system that works great in the virtual world but will not perform when called upon.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The team has modified the term to RoCoF. The team agrees the model improvements are needed. Modifications to model requirements will be covered by other projects addressing Order 901.	
Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	
Document Name	
Comment	
PNM agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE has the following additional comments for PRC-029-1:	

1. Texas RE recommends the new terms included in PRC-029-1 clearly state the voltage measurements included are at the high-side of the main transformer connecting to the BPS transmission system. Texas RE suggests the following changes (in bold):

Term(s): Continuous Operating Region – The range of voltages, measured at the high-side of the **BPS** main power transformer, that are ≥ 0.9 per unit and ≤ 1.1 per unit.

Mandatory Operating Region – The range of voltages, measured at the high-side of the **BPS** main power transformer, that are > 0.1 per unit and < 0.9 per unit – or – > 1.1 and ≤ 1.2 per unit.

Permissive Operating Region – The range of voltages, measured at the high-side of the **BPS** main power transformer, that is ≤ 0.1 per unit.

2. Consider changing 'each IBR' to 'each IBR Facility' for all the requirements.

3. For consistency, consider modifying the title of the standard to (in bold):

Title: Frequency and Voltage Ride-through Requirements for Inverter-Based **Generating** Resources

4. Consider changing 4.2.1 to **BES** IBRs (instead of BPS IBRs) to be consistent with other PRC standards such as proposed reliability standards PRC-028-1 and PRC-024-4.

5. Consider changing voltage (per unit) in Attachment 1 (third row) to greater than 1.05 pu only (i.e. remove the equal 1.05 criterion). Typical BES and BPS systems are expected to operate continuously for voltage levels 0.95 – 1.05 pu.

Attachment 1 - changes

In Table 1 & Table 2 change > 1.05 to >1.05

Add the following to Table 1 and 2:

Voltage (per unit): > 0.9 Minimum Ride-Through: Continuous

Voltage (per unit): < 1.05 Minimum Ride-Through: Continuous

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. **Operation Region:** The team agrees and has removed the operation regions as defined terms and added clarity on the point of measurement. **Attachment 1:** Tables and Figures in Attachment 1 have been revised to add clarity on the operation region. Additionally, values were corrected. **Applicability**: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	
Document Name	
Comment	
• GTC recommends increasing the implementation timeline to be 12 to 18 months after the effective date of the applicable governmental authority's order approving for both the PRC-024-4 and PRC-029-1 standards. • There were no balloting questions provided for the language changes in the PRC-024-4 standard. GTC recommends providing balloting questions for the industry to respond to the changes in the PRC-024-4 standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Implementation Plan:** The Implementation Plan has been revised to follow the effective date of PRC-028. All revisions to Reliability Standards directed by Order 901 must be fully implemented by 2030. Question 4 was provided to allow for any other responses to the proposed changes.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	
Document Name	
Comment	

NERC should remain consistent with their revised Rules of Procedure by avoiding the use of “BPS IBR” terminology in the applicable facilities. This is overly broad and can lead to misinterpretation for Generator Owners who own IBRs that do and do not fit the 60 kV and 20 MVA thresholds. The third question in the Project 2020-06 comment form, copied below, is a clearer definition of IBR which NERC has determined has a material impact to the BPS. NERC should consider adopting this terminology in PRC-029

Section 4. Applicability:

4.1 Functional Entities: Generator Owner, Generator Operator

4.2 Facilities: (1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Applicability: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and North American Generator Forum (NAGF) on question 4

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. See response to EEI and NAGF.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	
Dominion Energy supports EEI comments. In addition, we have the following coments: The term BPS IBRs and IBR Registration Criteria are not clear-cut Facilities. The standard should reference terms available for use in the NERC Glossary of Terms to determine applicability, such as the BES defintion. As stated in the EEI comments, the BES defintion would be the appropriate place to address defintions of this type. The Effective Date of 6 months following approval by FERC is too short for Generator Owners and Transmission Owners that own numerous IBR generating sites, to develop internal controls and processes; and perform the necessary compliance evaluations and possible settings changes to meet the ride-through criteria. Conversely, 6 months after the effective date is too long for documenting Limitations per Requirement R6. The documentation of limitations is typically done during the compliance analysis and study. A staggered implementation plan, that takes into account the registration and requirements for Level 2 GO registrations should be designed and implemented. The Implementation Plan should also consider those IBRs that are approved to be built and have had their Interconnection Studies approved. The contracts for building these sites are signed years in advance with the inverters ordered. A staggered applicability for R6 should be considered that allow for projects in service prior to 2027 or 2028 to be eligible for equipment limitations and those in service after to meet the performance criteria without limitations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI. **Applicability**: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.	

Implementation Plan: The Implementation Plan has been revised to follow the effective date of PRC-028. All revisions to Reliability Standards directed by Order 901 must be fully implemented by 2030.
Exemptions: The scope of allowable exemptions within R4 (previously R6) is consistent with the regulatory directives of Order No. 901. New IBR (those in-service after the effective date of PRC-029) cannot apply for exemption per the Order.

George E Brown - Pattern Operators LP - 5

Answer	
Document Name	

Comment

Pattern Energy supports GRE's comments for this question.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. See response to GRE.

Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies

Answer	
Document Name	

Comment

The SDT explains in the draft PRC-029-1 Technical Rationale that "An IBR becomes noncompliant with PRC-029 only when an event in the field occurs that shows that one or more requirements were not satisfied." This, coupled with the removal of IBRs from PRC-024 applicability, would result in a lack of accountability until actual harm (i.e., failure to adequately support the reliability of the BES during a system event) occurs for IBRs not prepared to meet the performance requirements. There would not be auditable and enforceable requirements for owners of IBRs to proactively take action to reasonably ensure the performance requirements will be met. Reliability standards exist to prevent potential harm, which minimizes actual harm.

While RF acknowledges the observed limitations of the existing PRC-024 standard in preventing the undesirable responses of IBRs to the system disturbance events cited in the SAR, RF does not support the whole-sale elimination of frequency and voltage protection settings verification requirements for IBRs. Generator frequency protection settings verification is critical in ensuring UFLS programs are adequately coordinated with generator capabilities, and RF does not wish to rely on self-revealing events to determine where miscoordination exists between IBR frequency protection and UFLS. Unless additional verification requirements are added to PRC-029, RF believes PRC-024 should remain applicable to IBRs.

RF notes that the range of system conditions in which PRC-029 would require IBRs to remain online appear to be significantly larger than those established in PRC-024 (which would remain applicable to synchronous generators). Although the unique capabilities of IBRs may support such a large expansion for only IBR resource types, additional discussion of the technical justification for this expansion would be useful.

Regarding implementation, RF finds a 12-month implementation period acceptable.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
Capability and Performance Measures: The team agrees that the ability to validate the capability of each applicable IBR was not clear from the initial draft. Changes have been made to ensure the design/capability of each IBR can be validated prior to an event – in addition to retaining the event and performance-based requirements.
Please refer to the TR for clarity regarding IBR performance measures.

Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment

The implementation plan is also very aggressive and for some generators may be impossible to meet.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Thank you for your comment. **Implementation Plan:** The Implementation Plan has been revised to follow the effective date of PRC-028. All revisions to Reliability Standards directed by Order 901 must be fully implemented by 2030

Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	

Comment

- The new performance-based approach opens us up to a lot of issues with other tripping/cessation besides basic overvoltage/under voltage/frequency that our operations team has seen during events.
    - This protection is not modeled in basic models right now and will require substantial effort to ensure we can perform as required. AES CE requests that the Implementation Plan be modified to use a phased-in approach for existing sites to allow adequate time to prepare for these performance requirements.

    Additionally, the standard and rationale is absent of language on studies/assessments that should be performed. AESCE believes that providing examples of the types of studies and assessments that should be run to ensure that resources would perform as expected is necessary for reliability and adequate implementation of this standard by GOs.

- Please provide additional clarification on acceptable limitations under R6. Language such as "hardware replacements or other costly upgrades" from the Technical rationale document is vague and open to interpretation.
- AESCE would like the SDT to consider the challenges with ensuring plants, particularly legacy operational plants, can ride through per the requirements. To ensure this or identify equipment limitations, studies and equipment information is necessary and is not available for most legacy equipment.
- First, EMT studies and RMS model studies are necessary to study plant ride-through capabilities specified in the standard. However, there are significant challenges with these models today that should be considered in the implementation and equipment limitations. Quality EMT models including all equipment information needed are not available for legacy equipment (inverters, PPCs). Many legacy inverters do not have an EMT model, and those that do have models that are not adequately validated against equipment performance. Creation of models is either not supported or can be developed at a very high cost. Models created after the inverters were initially released are of inadequate quality because the equipment is no longer able to be in a lab environment.
    - To consider this, AESCE suggests that the SDT include exceptions for legacy equipment where the performance may not be predictable due to a lack of modeling or inverter information.
- Second, not all current models are of the level of quality that they can be used to ensure that the plant will ride-through as specified in the standard. The implementation of this standard should consider the significant resources and cost to implement.

- Third, manufacturer support for GOs to ensure that IBRs only trip to prevent equipment damage as noted in R2.5 is limited for existing equipment and is unavailable for some legacy equipment. Additionally, this support has been very costly for us to obtain and will strain manufacturer resources to provide.

Considering these limitations, AESCE suggests that the SDT include exceptions for legacy equipment where 1. The performance may not be predictable due to a lack of accurate models at a reasonable cost, 2. Equipment limits may not be known or where the cost may be egregious to provide.

- Expectations for demonstrating and checking performance are unclear, please add language or examples to illustrate how the SDT believes this will happen.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Implementation Plan: The Implementation Plan has been revised to follow the effective date of PRC-028. All revisions to Reliability Standards directed by Order 901 must be fully implemented by 2030.
Models: The team agrees the model improvements are needed however those will not be addressed within PRC-029. Modifications to model requirements will be covered by other projects addressing Order 901.
Regarding Exemptions: The team has modified Requirement R4 (previous R6) to include clarity on allowable exemptions and requires identification of such limitations to be documented and submitted.
Scope: The team acknowledges challenges with some plants meeting Ride-through requirements per PRC-029. The scope of these performance requirements and allowable exemptions is consistent with the regulatory directives of Order No. 901 and cannot be modified as suggested.

Rhonda Jones - Invenergy LLC - 5

Answer	
Document Name	

Comment

Invenergy thanks the drafting team for their work and the opportunity to provide comments.

Regarding the proposed Implementation Plan for R6, six months may not be enough time to gather all applicable documentation regarding equipment limitations. There are a limited number of vendors of IBR technology that have serviced the industry, and they will be inundated with requests for documentation once the standard becomes effective.

On a final note, NERC appears to have borrowed from some of the requirements within IEEE 2800-2022 and brought them into this standard (e.g. the phase-angle jump requirement, etc.). Invenergy believes it would be incorrect to adopt such requirements until the work of IEEE Working Group p2800.2 has been completed and their recommended practice standard published. Without such an approved recommended practice standard, there is no industry-wide accepted set of procedures for verifying conformity to the borrowed requirements in PRC-029-1.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
The Implementation Plan has been modified to 12 months following the effective date of PRC-028.
Requirements within the NERC PRC-029 address the scope of the SAR and draw from IEEE2800 but are mandatory and enforceable requirements.

David Jendras Sr - Ameren - Ameren Services - 1,3,6

Answer	
Document Name	

Comment

Ameren agrees with EEI's comments.

In addition, Ameren believes that ride-through requirements should be in a MOD standard instead of a PRC standard. Protection relay engineers do not have access to the necessary IBR equipment and do not have the expertise to determine the root cause of why an IBR behaved in an unexpected manner. Thus, evaluating and establishing a CAP to correct a reduction in power following a disturbance will not be performed by a relay engineer.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. See response to EEI. **Capability and Performance Measures**: . The team agrees that the ability to validate the capability of each applicable IBR was not clear from the initial draft. Changes have been made to ensure the design/capability of each IBR can be validated prior to an event – in addition to retaining the event and performance-based requirements.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	
Document Name	
Comment	
Invenergy thanks the drafting team for their work and the opportunity to provide comments. Regarding the proposed Implementation Plan for R6, six months may not be enough time to gather all applicable documentation regarding equipment limitations. There are a limited number of vendors of IBR technology that have serviced the industry, and they will be inundated with requests for documentation once the standard becomes effective. On a final note, NERC appears to have borrowed from some of the requirements within IEEE 2800-2022 and brought them into this standard (e.g. the phase-angle jump requirement, etc.). Invenergy believes it would be incorrect to adopt such requirements until the work of IEEE Working Group p2800.2 has been completed and their recommended practice standard published. Without such an approved recommended practice standard, there is no industry-wide accepted set of procedures for verifying conformity to the borrowed requirements in PRC-029-1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The Implementation Plan has been modified to 12 months following the effective date of PRC-028. Requirements within the NERC PRC-029 address the scope of the SAR and draw from IEEE2800 but are mandatory and enforceable requirements.	
Brittany Millard - Lincoln Electric System - 5	
Answer	
Document Name	

Comment
With regards to PRC-029 we woulkd ask: **1. Clarify and emphasize that limitations must not be construed as complete exemptions.** If entities are unable to ride-through portions of the ride-through curve, this does not automatically exempt them from complying with the balance of the ride-through curve as described in the Technical Rationale. While this is clear in the Technical Rationale for Requirement R6 (page 9), this point needs to be brought out more clearly in the PRC-029 standard itself. **2. Expand PRC-029 to require Corrective Action Plans be implemented to remove equipment limitations within a specified timeline**. **3. we recommend modifying Section 4 of PRC-029-1 as follows:** 4. Applicability: 4.1 Functional Entities: 4.1.1 Generator Owner that owns equipment identified in section 4.2, 4.1.2 Transmission Owner that owns equipment as identified in section 4.2 Generator Owner that owns equipment identified in section 4.2. 4.2 Facilities: to include 4.2.3 Shunt static or dynamic reactive device(s) associated with IBR that either have or contribute to meeting the performance requirements. **4. The standard is event-based compliance that requires installing recorded equipment data with higher sampling rates at all applicable legacy IBR Facilities. Therefore, we suggest that the implementation plan for PRC-029 should be aligned with Project 2021-04 (PRC-028-1) for the legacy IBR. Also, we suggest having a different implementation plan for the legacy IBR from IBR connected after the approval date of PRC-029.** **5. Some clarity on how these requirements would be enforced in the location where no data recording is available at the IBR facility during system events.** **6. M1-M5 required GO to maintain the evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in Requirement R1-R5. What are the criteria for selecting the event(s) that should be analyzed to demonstrate compliance with the VRT, FRT, and VRT performance requirement(s)? If the performance does not meet the requirement(s), do Generator Owner needs to present a correction action plan and provide it to each applicable Reliability Coordinator. We suggest coordinate this project 2020-02 (PRC-029) with project 2023-02(PRC-030) regarding the IBR ride-through performance analysis.**

7. We suggest that the drafting team ensure consistent language is used in the section 4.2 “Facilities” section with the other projects such as Project 2021-04 (PRC-028) and 2023-02(PRC-030). We suggested the following language be included in the applicability section. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

8. The title of the standard calls out “Inverter-Based Generating Resources”, should “Generating” be removed to be consistent?

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Exemption: The team agrees that only specific ride-through limitations would be applied and there is no global exemption intended. Language has modified within the Requirement R4 (previous R6) as well as the Technical Rationale to clarify this.
CAPs: The scope for some documented exemptions is consistent with the Order.
Applicability: Language within the applicability section has been modified per other suggestions.
Implementation Plan: The Implementation Plan has been modified to 12 months following the effective date of PRC-028.
PRC-029 compliance: The team agrees that the ability to validate the capability of each applicable IBR was not clear from the initial draft. Changes have been made to ensure the design/capability of each IBR can be validated prior to an event – in addition to retaining the event and performance-based requirements. PRC-028 compliance will be established within PRC-028 and the associated Implementation Plan.
Applicability: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.
Title: The title has been modified as suggested.

Ben Hammer - Western Area Power Administration - 1

Answer	
Document Name	

Comment

Several enhansments to PRC-029 are requested:

1. **Clarify and emphasize that limitations must not be construed as complete exemptions.** If entities are unable to ride-through portions of the ride-through curve, this does not automatically exempt them from complying with the balance of the ride-through curve as described in the Technical Rationale. While this is clear in the Technical Rationale for Requirement R6 (page 9), this point needs to be brought out more clearly in the PRC-029 standard itself. 2. **Expand PRC-029 to require Corrective Action Plans be implemented to remove equipment limitations within a specified timeline**. 3. **we recommend modifying Section 4 of PRC-029-1 as follows:** 4. Applicability: 4.1 Functional Entities: 4.1.1 Generator Owner that owns equipment identified in section 4.2, 4.1.2 Transmission Owner that owns equipment as identified in section 4.2 Generator Owner that owns equipment identified in section 4.2. 4.2 Facilities: to include 4.2.3 Shunt static or dynamic reactive device(s) associated with IBR that either have or contribute to meeting the performance requirements. 4. **The standard is event-based compliance that requires installing recorded equipment data with higher sampling rates at all applicable legacy IBR Facilities. Therefore, we suggest that the implementation plan for PRC-029 should be aligned with Project 2021-04 (PRC-028-1) for the legacy IBR. Also, we suggest having a different implementation plan for the legacy IBR from IBR connected after the approval date of PRC-029.** 5. **Some clarity on how these requirements would be enforced in the location where no data recording is available at the IBR facility during system events.** 6. **M1-M5 required GO to maintain the evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in Requirement R1-R5. What are the criteria for selecting the event(s) that should be analyzed to demonstrate compliance with the VRT, FRT, and VRT performance requirement(s)? If the performance does not meet the requirement(s), do Generator Owner needs to present a correction action plan and provide it to each applicable Reliability Coordinator. We suggest coordinate this project 2020-02 (PRC-029) with project 2023-02(PRC-030) regarding the IBR ride-through performance analysis.** 7. **We suggest that the drafting team ensure consistent language is used in the section 4.2 “Facilities” section with the other projects such as Project 2021-04 (PRC-028) and 2023-02(PRC-030). We suggested the following language be included in the applicability section. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.**

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. **Exemption**: The team agrees that only specific ride-through limitations would be applied and there is no global exemption intended. Language has modified within the Requirement R4 (previous R6) as well as the Technical Rationale to clarify this. **CAPs**: The scope for some documented exemptions is consistent with the Order. **Applicability**: Language within the applicability section has been modified per other suggestions. **Implementation Plan:** The Implementation Plan has been modified to 12 months following the effective date of PRC-028. **PRC-029 compliance**: The team agrees that the ability to validate the capability of each applicable IBR was not clear from the initial draft. Changes have been made to ensure the design/capability of each IBR can be validated prior to an event – in addition to retaining the event and performance-based requirements. PRC-028 compliance will be established within PRC-028 and the associated Implementation Plan. **Applicability**: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
New terms are introduced on page 2 (Continuous **Operating** Region, Mandatory **Operating** Region, Permissive **Operating** Region). Requirement R1 includes the words "**operation** regions" and R2 includes the terms "Continuous **Operation** Region" (Part 2.1) and "Mandatory **Operation** Region" (Part 2.2). We recommend the drafting team review all instances of "**operation** region" within the standard and determine if it should be changed to "**operating** region" to align with the proposed terms. Or conversely, consider if the word "Operating" within the defined terms should be changed to "Operation". For Requirement R2: How will the Generator Owner or Transmission Owner of an applicable IBR be made aware that a PRC-029-1 applicable "System disturbance" has occurred within their associated Planning Coordinator(s) area(s)? Part 2.1.2 refers to "requirements [for active or reactive power preference] specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator".	

Part 2.2.2 refers to a "certain magnitude of reactive power response to voltage changes" or a preference for "active power priority instead of reactive power priority" that can be specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Part 2.4 refers to a "lower post-disturbance active power level requirement" or "different post-disturbance active power restoration time" specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

With up to four registered entity types being able to provide these preferences (spanning the operations and planning time horizons), is there a chance the Generator Owner or Transmission Owner of an applicable IBR will receive conflicting requirements? Is there a corresponding standard(s) that includes a requirement(s) for the TP, PC, RC or TOP to specify these preferences?

For Requirement R3, how will the Generator Owner or Transmission Owner of an applicable IBR know that a PRC-029-1 applicable transient overvoltage period has occurred within their associated Planning Coordinator(s) area(s)?

For Requirement R4, how will the Generator Owner or Transmission Owner of an applicable IBR know that a PRC-029-1 applicable frequency excursion event has occurred within their associated Planning Coordinator(s) area(s)?

Requirement R6 requires that a Generator Owner or Transmission Owner of an applicable IBR that has a documented equipment limitation, that prevents it from meeting voltage ride-through requirements as detailed in Requirements R1 and R2, communicate each equipment limitation to their associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s). Since the Transmission Operator is also identified in R2, it seems strange to omit the TOP from R6.

With regard to the Implementation Plan, having PRC-024-4 becoming effective six months after approval is reasonable, since this Standard's changes are primarily to limit its applicability to synchronous generators / condensers, and they should already be compliant with the existing version.

However, having PRC-029-1 become effective six months after approval is not reasonable. The technical rationale doesn't provide guidance on how to provide evidence of compliance. It can take considerable time to develop and perform the required analyses, generate potential design changes to make the required setting changes, and implement them.

We recommend providing implementation guidance or technical data showing how to demonstrate performance.

We also recommend allowing at least 24 months to achieve full compliance with the proposed requirements in PRC-029-1.

Likes 0	
Dislikes 0	

Response	
Thank you for your comments. **Operation Region**: The team agrees and has removed the operation regions as defined terms. **Measures (events)**: The evidence of compliance for disturbance monitoring that are associated with voltage and frequency excursions that were System disturbances and would be identified for analysis or another trigger by an applicable entity within draft PRC-030. Evidence of disturbance monitoring of IBR associated with those disturbances would be triggered by compliance under the requirements for PRC-030. **R2 General operation expectations**: Requirement 2.2. was clarified to allow for operating instructions from the TOP/PC/RC/TP to be followed but only <u>if</u> specified. Further usage of AVR was removed from the requirement. **Previous Requirement R3:** This requirement and attachment 2 have been removed. **TOP**: This was an error. The TOP has been added to Requirement R4 (previous r6). **Implementation Plan**: The Implementation Plan has been modified to 12 months following the effective date of PRC-028. All revisions to Reliability Standards directed by Order 901 must be fully implemented by 2030. **Capability and Performance Measures**: The team agrees that the ability to validate the capability of each applicable IBR was not clear from the initial draft. Changes have been made to ensure the design/capability of each IBR can be validated prior to an event – in addition to retaining the event and performance-based requirements.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation supports EEI's and NAGF's additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI and NAGF.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	

Comment	
FirstEnergy finds inconsistency in how these newly created standards are applying IBR applicability in the Applicable Section – leading to confusion from one project and standard to another. We request these Drafting Teams align these Applicable Sections. FE cannot support the Implementation Plan until it is clear how R2 will be clarified toward requirement responsibility.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Applicability:** The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft. **R2 General operation expectations**: Requirement 2.2. was clarified to allow for operating instructions from the TOP/PC/RC/TP to be followed but only if specified. Further usage of AVR was removed from the requirement.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports comments provided by the NAGF	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to NAGF.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District,	

3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	
Document Name	
Comment	
The language proposed in the Applicability section of PRC-029-1 is inadequate to define what IBR Facilities this Standard would apply to. The terms “BPS IBRs” and “IBR Registration Criteria” are too broad, vague, and undefined, and could include all IBRs interconnected to the Bulk Power System at any voltage level. SMUD recommends the Standards Drafting Team use similar language to that proposed in NERC Standards Project 2021-04 Modifications to PRC-002 - Phase II, PRC-028-1 draft #2. If modified accordingly, the Applicability section would state: “4.1. Functional Entities: 4.1.1. Generator Owner that owns equipment as identified in section 4.2 4.1.2. Transmission Owner that owns equipment as identified in section 4.2 4.2. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Applicability**: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.	
Brian Lindsey - Entergy - 1	
Answer	

Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Michael Brytowski - Great River Energy - 3	
Answer	
Document Name	
Comment	
1. Clarify and emphasize that limitations must not be construed as complete exemptions. If entities are unable to ride-through portions of the ride-through curve, this does not automatically exempt them from complying with the balance of the ride-through curve as described in the	

Technical Rationale. While this is clear in the Technical Rationale for Requirement R6 (page 9), this point needs to be brought out more clearly in the PRC-029 standard itself. **2. Expand PRC-029 to require Corrective Action Plans be implemented to remove equipment limitations within a specified timeline**. 3.**. we recommend modifying Section 4 of PRC-029-1 as follows:** 4. Applicability: 4.1 Functional Entities: 4.1.1 Generator Owner that owns equipment identified in section 4.2, 4.1.2 Transmission Owner that owns equipment as identified in section 4.2 Generator Owner that owns equipment identified in section 4.2. 4.2 Facilities: to include 4.2.3 Shunt static or dynamic reactive device(s) associated with IBR that either have or contribute to meeting the performance requirements. 4**. The standard is event-based compliance that requires installing recorded equipment data with higher sampling rates at all applicable legacy IBR Facilities. Therefore, we suggest that the implementation plan for PRC-029 should be aligned with Project 2021-04 (PRC-028-1) for the legacy IBR. Also, we suggest having a different implementation plan for the legacy IBR from IBR connected after the approval date of PRC-029.** 5**. Some clarity on how these requirements would be enforced in the location where no data recording is available at the IBR facility during system events.** **6. M1-M5 required GO to maintain the evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in Requirement R1-R5. What are the criteria for selecting the event(s) that should be analyzed to demonstrate compliance with the VRT, FRT, and VRT performance requirement(s)? If the performance does not meet the requirement(s), do Generator Owner needs to present a correction action plan and provide it to each applicable Reliability Coordinator. We suggest coordinate this project 2020-02 (PRC-029) with project 2023-02(PRC-030) regarding the IBR ride-through performance analysis.** **7.** We suggest that the drafting team ensure consistent language is used in the section 4.2 "Facilities" section with the other projects such as Project 2021-04 (PRC-028) and 2023-02(PRC-030). We suggested the following language be included in the applicability section. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.	
Likes 0	

Dislikes 0	

Response

Thank you for your comment.
Exemption: The team agrees that only specific ride-through limitations would be applied and there is no global exemption intended. Language has modified within the Requirement R4 (previous R6) as well as the Technical Rationale to clarify this.
CAPs: The scope for some documented exemptions is consistent with the Order.
Applicability: Language within the applicability section has been modified per other suggestions.
Implementation Plan: The Implementation Plan has been modified to 12 months following the effective date of PRC-028.
PRC-029 compliance: The team agrees that the ability to validate the capability of each applicable IBR was not clear from the initial draft. Changes have been made to ensure the design/capability of each IBR can be validated prior to an event – in addition to retaining the event and performance-based requirements. PRC-028 compliance will be established within PRC-028 and the associated Implementation Plan.
Applicability: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	
Document Name	

Comment

BC Hydro appreciates the drafting team's efforts and the opportunity to comment, and offers the following:

1. The Applicability section (A.4.2 Facilities) of PRC-029-1 references BPS IBR and IBR Registration Criteria. BC Hydro suggests that the Facilities section instead use wording reflective of the proposed Category 2 GO as included in the recent revisions to the NERC Rules of Procedure.
2. BC Hydro suggests that the use of "shall" in the language of the Measures may not be appropriate as it could imply a new Requirement or expansion on the existing Requirement. The obligation of having evidence is adequately established and enforceable via the CMEP.
3. The Measure M3 of PRC-029-1 references "the associated Planning Coordinator". The associated Requirement R3 does not. BC Hydro suggests that this is not needed as there may be switching events within a PC's area that do not create overvoltage conditions to trigger R3 for certain IBRs within the PC area.

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. **Applicability:** The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft. **Measures**: The team agrees and has removed the word “shall” from the Measures. **Previous M3**: The previous requirement R3 has been removed.	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
Applicability: In Introduction, Section 4.2.2, it is not obvious what aspect of ‘IBR Registration Criteria’ makes an IBR an ‘applicable’ IBR – is it simply that an IBR meets NERC Registration Criteria? This bullet point should be elaborated to ensure clarity. **Event-Based Standard:** The IESO has concerns with this standard being an event-based standard, in that it does not necessarily provide an assurance of reliability before events occur, such as would be provided by having an engineering analysis, or bench-testing/real-time simulations of controls equipment that indicates successful ride through of prescribed disturbances is expected. Without disturbance events that challenge the IBRs to perform properly it would be unknown if the IBR is compliant. At a minimum, the measures (e.g, M2-M5) should be extended to allow a statement that no such events are known to have occurred to ‘count’ as evidence of compliance. **Presentation of Ride Through Ranges:** The intended ride through requirements could be made more clear if the ‘minimum ride through times’ were associated with precisely stated, *non-overlapping ranges* of voltages or frequencies, such as in the example ‘Table 2’ provided by the IESO in the comments above, for Section 2.1.	

Nominal Voltages:

To ensure clarity of intent in note #4 of Attachment 1, the 'nominal' system voltage values should be listed as they are in the existing PRC-024, i.e., “(e.g., 100 kV, 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 400 kV, 500 kV, 765 kV, etc.)”

Harmonize Tables, Figures, Requirements:

The levels of voltage/frequency excursion and the minimum ride through times for all tables, figures, and any associated performance requirements that modify the requirements at given times should be carefully reviewed and harmonized. There are presently some conflicting entries in the tables/figures.

Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	

Response

Thank you for your comment.
Applicability: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.
Capability and Performance Measures: The team agrees that the ability to validate the capability of each applicable IBR was not clear from the initial draft. Changes have been made to ensure the design/capability of each IBR can be validated prior to an event – in addition to retaining the event and performance-based requirements.
Attachment 1: Tables and Figures in Attachment 1 have been revised to add clarity on the operation regions and the values in the tables. This should address issues with identifying more than one row.
Attachment 1 clarification on 500kv: Attachment 1 sets the minimum expectation for operation regardless of voltage class. Expanding the no trip zone for 500kV may still be done based on the system need.

Chantal Mazza - Hydro-Quebec (HQ) - 1 - NPCC

Answer	
Document Name	

Comment

We are concerned that the standard refers to a defined term for IBR which has yet to be adopted in project 2020-06.

We suggest that the drafting team ensure consistent language is used in the section 4.2 “Facilities” section with the other projects such as 2021-04 (PRC-028) and 2023-02(PRC-030). Section 4.2.2 refers to IBR Registration criteria, however it is our understanding that section 4.2.1 would refer to GOs and TOs “that own equipment as identified in section 4.2” and where section 4.2 would indicate “the Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.” .

We question why “attachment 1” and “Requirement R6” are written in bold.

Attachment 1: should the “including, but not limited to” in table 2 include the same list (or minimally the same wording) that is found in the technical rationale of the IBR definition in project 2020-0?. For example, the IBR list in 2020-06 refers to “solar photovoltaic” whereas table 2 refers to “photovoltaic (PV)”.

In what standard does the PC/TP define the applicable table in point 3 of section 2 in attachment 1? Same question for the voltage base for per unit calculation in both Attachment 1 and 2. Is there a corresponding requirement in another standard that requires the PC/TP to do this?

· Terms : Mandatory and permissive operation should be defined based on the attachment figures allowing for interconnections to use different requirements

· A-4.2.2 What is the IBR registration criteria? Add a clear reference and make sur the user understands what the IBR registration criteria is.

· B-R2-2.1 Attachment 1 only uses "no-trip zone". Define continuous operating region more clearly in the table (similar to what is done in PRC-024-4)

· B-R2-2.1.2 Can the TP ask for a mix of active/reactive power based on a predetermined ratio (currently only indicated as active or reactive).

· B-R2-2.2 Attachment 1 only uses "no-trip zone". Define "mandatory operation region" in Attachment 1.

· B-R2-2.4 Permissive operation region is not used or defined in attachment 1.

· B-R3. The document refers to an overvoltage value of 1.2pu. It should refer to a voltage exceeding the mandatory operating region in order for Interconnections to set their own overvoltage table.

· B-R3. Since R6 does not apply to this requirement, what will be done with existing IBR that cannot ride through these overvoltages ? An exemption clause is required for existing IBR that cannot be modified or upgraded.

· B-R4. The 5Hz/s value should be moved to Attachment 3 and B-R4 should only refer to the value in the Attachment. · B-R4. Since R6 does not apply to this requirement, what will be done with existing IBR that cannot ride through these frequencies and ROCOF ? (for instance, for all the HQ connected projects, the ROCOF requirement was 4Hz/s) An exemption clause is required for existing IBR that cannot be modified or upgraded. · B-R5. Since R6 does not apply to this requirement, what will be done with existing IBR that cannot ride through this phase angle jump ? An exemption clause is required for existing IBR that cannot be modified or upgraded. · Attachment 1. Tables 1 and 2: Indicate what is considered as “continuous operation”, “mandatory operation” and “permissive operation” in an additional column. · Attachment 1. HQ needs a Quebec regional variance since the Québec Interconnection has its own requirements in this regard. · Attachment 2. Bullet 3: This sentence is hard to read. Proposed replacement: "Each IBR shall not trip unless the cumulative time of one or more instances in which the instantaneous voltage exceeds the respective voltage threshold over a 1-minute time window exceeds the minimum ride-through time" · Attachment 2. HQ needs a Quebec regional variance since the Québec Interconnection has its own requirements in this regard. · Attachment 3. This attachment should also include the maximum absolute ROCOF value. · Attachment 3. HQ needs a Quebec regional variance · B-R2-2.1.2 Which entity between Transmission Planner, Planning Coordinator, Reliability Coordinator and Transmission Operator has priority to specify those requirements? · B-R2-2.4 Which entity between Transmission Planner, Planning Coordinator, Reliability Coordinator and Transmission Operator has priority to specify those requirements?

Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	

Response
Thank you for your comment. **IBR**: The team has removed the currently undefined term IBR and will include the term once it has been approved.

Applicability: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.
Attachment 1: Tables and Figures in Attachment 1 have been revised to add clarity on the operation regions. The range of values in row #4 of Tables 1 and 2 to clarify the continuous operation region. Changes were made to align terms used throughout.
R2.1.2 (previous R2.1.1) and R2.1.3 (previous 2.1.2): Language was clarified in R2.1.2 and R2.1.3 to address apparent vs reactive power limits per above and other comments. R2.1.3 has been clarified that the GO/TO shall follow provided TP/PC/RC/TOP requirements if those are provided. Requirement R2 subparts require the GO/TO to follow provided TP/PC/RC/TOP restoration time or active power recovery threshold requirements – if different than default values in the sub-requirement. R2 does not intend that values other than the default values must be specified, only that performance for the plant/facility will be evaluated in accordance with those values if provided. Language has been added to M2 to clarify what evidence is expected if the TP/PC/RC/TOP provide other performance requirements.
Previous Requirement R3: This requirement has been removed.
Exemptions: The scope of allowable exemptions within R4 (previously R6) is consistent with the regulatory directives of Order No. 901. Frequency cannot apply for exemption. New IBR cannot apply for exemption. This is consistent with the ordered directives.
Previous Requirement R5: This requirement has been removed and the non-fault exclusionary language has been added to R1. A requirement to notify the Generator Owner or Transmisson Owner and to evaluate performance when the plant/facility tripped because of a switching event is in the current draft PRC-030.
Quebec variant: The team will coordinate with Hydro Quebec to include their variant as identified by Hydro Quebec.
Priority: This issue is out of scope for the team. The language in the requirement is to make allowance for established operational instructions

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

- Evidence Retention: We would suggest that the evidence retention period for both Standards should be changed from five years to three years, to be consistent with other NERC Standards.

- The standard is event-based compliance that required installing recorded equipment data with higher sampling rates at all applicable legacy IBR Facilities. Therefore, we recommend that the implementation plan for PRC-029 should be aligned with Project 2021-04 (PRC-028-1) for the legacy IBR. Also, we suggest have different implementation plan for the legacy IBR from IBR connected after the approval date of PRC-029.

- Some clarity how these requirements would be enforced in a location where no data recording is available at an IBR facility during system events.

- M1-M5 required the GO to maintain the evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in Requirement R1-R5. What are the criteria for selecting the event(s) that should be analyzed to demonstrate compliance with the VRT, FRT and VRT performance requirement(s)? If the performance does not meet the requirement(s), do Generator Owner need to present a corrective action plan and provide it to each applicable Reliability Coordinator. We suggest coordinating this project 2020-02 (PRC-029) with project 2023-02(PRC-030) regarding the IBR ride-through performance analysis.

- R2: We agree with the present flexibility that some of the IBR VRT performance could be modified to meet the individual system needs by the applicable Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator. However, some clarity may be required on how this process is initiated and what type of evidence is required to demonstrate the request is received and implemented. This may be an additional requirement assigned to the Transmission Planner. Each Transmission Planner, Planning Coordinator, and Transmission Operator that jointly specifies the following voltage ride-through performance requirements within their area(s) different than those specified under R2, shall make those requirements available to each associated applicable IBR Generator Owner and Transmission Owner.

- We suggest that the drafting team ensures consistent language is used in the section 4.2 "Facilities" section with the other projects such as Project 2021-04 (PRC-028) and 2023-02(PRC-030). We suggest the following language be included in the applicability section. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

- R3: we suggest adding to the attachment 2 how the instantaneous transient overvoltage should be calculated (such as what is the pu based on? and the minimum sampling rate?)

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Retention: The compliance retention period was modified to align with PRC-030.
Implementation Plan: The Implementation Plan has been modified to 12 months following the effective date of PRC-028. All revisions to Reliability Standards directed by Order 901 must be fully implemented by 2030.

Capability and Performance Measures: . The team agrees that the ability to validate the capability of each applicable IBR was not clear from the initial draft. Changes have been made to ensure the design/capability of each IBR can be validated prior to an event – in addition to retaining the event and performance-based requirements.
Measures - data: The compliance measures for demonstration of performance were revised from "actual recorded data" to "actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data".
R2.1.2 (previous R2.1.1) and R2.1.3 (previous 2.1.2): Language was clarified in R2.1.2 and R2.1.3 to address apparent vs reactive power limits per above and other comments. R2.1.3 has been clarified that the GO/TO shall follow provided TP/PC/RC/TOP requirements if those are provided. Requirement R2 subparts require the GO/TO to follow provided TP/PC/RC/TOP restoration time or active power recovery threshold requirements – if different than default values in the sub-requirement. R2 does not intend that values other than the default values must be specified, only that performance for the plant/facility will be evaluated in accordance with those values if provided. Language has been added to M2 to clarify what evidence is expected if the TP/PC/RC/TOP provide other performance requirements.
Applicability: The applicability section has been modified to include more specific details on currently applicable facilities. The IBR that will be included as part of registration changes (Category 2 assets) will be added following the approval of pending changes to the NERC Rules of Procedure. These are currently excluded from this draft.
Previous Requirement R3: This requirement has been removed.

Leah Gully - Madison Fields Solar Project, LLC - 5 - RF

Answer	
Document Name	

Comment

1. The proposed Standard refers to four different operating regions (no-trip zone, Continuous Operation Region, Mandatory Operation Region, and Permissive Operating Region). The different zones require Generator Owners to take different actions based on the number of disturbances and deviations that occur within in a 10 second period as well as the positive sequence voltage on the high side of the MPT. The ability of plant operators or inverter controls to identify, track, and respond effectively to all these variables is unrealistic. Why are these requirements not applied to non-IBR owners?
2. In R1, GOs are required to ensure that IBRs continue to "exchange current in accordance with the no-trip zones and operation regions as specified in Attachment 1." The Standard does not define the term "exchange current". Please define this term.
3. Measure 1 requires the Generator Owner and Transmission Owner to have actual recorded data for each applicable IBR demonstrating ridethrough adherence. This measure needs a timeframe for retention of the data.
4. The second half of the sentence in 2.1.1 doesn't appear to add any value to the sub-requirement. Please clarify what added operational requirement is meant by, "…and continue to deliver active power and reactive power up to its apparent power limit."

5. Requirement R2.1.2 allows four different entities to dictate each IBR's operating mode. This contradicts the requirements of VAR-001 which states that GOs must operate in voltage control mode unless exempted by the TOP. Recommend selecting one of these entities to determine the preference.
6. For overvoltage conditions greater than 140% Attachment 2 requires Generator Owners to distinguish and respond with different time delays, all less than or equal to 3 ms. Recommend requiring IBRs to delay their response to voltage excursions and program their IBRs to match the responses of synchronous machines.
7. Clarify Requirement 2.2.1 to address the expected operational response to close-in faults. Recommend the Standard specify separate performance requirements for close-in faults and more distant faults.
8. Requirement 2.2 appears to mandate that IBRs who operate in active power priority mode in the continuous operating region would be required to switch to the reactive power mode if a voltage disturbance occurs. What criteria are IBRs expected to use to determine when this switch should occur? What are IBRs expected to do if their inverters cannot be switched without software modifications?
9. The ride through requirements should all be specified in the same units of time.
10. Couldn't the voltage overshoot concerns addressed by Requirement 2.3 be addressed more reliably by slowing the response time of the IBR plant controllers to match that of synchronous generation?
11. Measure 2 requires the GO and TO to have actual recorded data during each system disturbance. Recommend establishing a timeframe for the retention of this data.
12. Measure 3 requires the GO and TO to have actual recorded data during each transient voltage event. Recommend establishing a timeframe for the retention of this data.
13. Measure 4 requires the GO and TO to have actual recorded data during each frequency excursion event. Recommend establishing a timeframe for the retention of this data.
14. Measure 5 requires the GO and TO to have actual recorded data during each positive sequence voltage phase angle changes that are less than 25 electrical degrees at the high side of the main transformer. Recommend establishing a timeframe for the retention of this data.
15. Requirement 6 has more specific requirements for an equipment limitation than is being proposed for the synchronous generators. Recommend PRC-029 reflect the wording proposed for PRC-024-4.
16. PRC-029 frequency ride-through is a single graph for all regions. The graph no trip zone is larger than the existing PRC-024 frequency no-trip zone for Eastern, Western, and ERCOT zones. The wording in the rationale is very soft (may be required). The change will cause the LFRT and HFRT settings to be updated as well as collector and transformer frequency settings. Recommend the frequency settings remain consistent with PRC-024 until the time that it is justified from grid events.

Likes 0	
Dislikes 0	
Response	

Thank you for your comments. **Ride-through expectations:** PRC-029 is not an equipment setting standard and sets minimum performance thresholds for determining Ride-through. Both the SAR and the assigned Order 901 direct the team to include capability and performance-based requirements for ride-through. The criteria does not cover any equipment failure during a disturbance. **Terminology "exchange current":** Also the team agrees for more clarity and has defined a new term for Ride-through and replaced language the requirements with this new term. Attachments have also been updated to utilize this term as the "Must Ride-through Zone". The operating regions have been removed as defined terms as well. **Measures (events)**: The evidence of compliance for disturbance monitoring that are associated with voltage and frequency excursions that were System disturbances and would be identified for analysis or another trigger by an applicable entity within draft PRC-030. Evidence of disturbance monitoring of IBR associated with those disturbances would be triggered by compliance under the requirements for PRC-030. **R2 – use of reactive power**: The team agrees that changes to clarify reaction power support in 2.1 was needed and made some adjustments to specify reactive power. This was broken into 2.1.1 and 2.1.2. **R2.1.2 (previous R2.1.1) and R2.1.3 (previous 2.1.2**): Language was clarified in R2.1.2 and R2.1.3 to address apparent vs reactive power limits per above and other comments. R2.1.3 has been clarified that the GO/TO shall follow provided TP/PC/RC/TOP requirements if those are provided. Requirement R2 subparts require the GO/TO to follow provided TP/PC/RC/TOP restoration time or active power recovery threshold requirements – if different than default values in the sub-requirement. R2 does not intend that values other than the default values must be specified, only that performance for the plant/facility will be evaluated in accordance with those values if provided. Language has been added to M2 to clarify what evidence is expected if the TP/PC/RC/TOP provide other performance requirements. **Previous R3**: Previous requirement R3 has been removed. Information on the TOV calculation has been added to Attachment 1. **R2- -dynamic switching**: Requirement 2.1.3 (previously 2.1.2) does not require dynamic switching between these two modes of operation. However, if that capability already exists, the operating mode would need to be specified by the TP, PC, RC, or TOP. **Previous R5**: Previous Requirement R5 has been removed and added as an exemption to Requirement R1. There is no exemption to trip within the no-trip zone for a fault. If there is a trip during non-fault initiated switching events, measurement data taken from the high-side of the MPT would include this information. The measure for R1 has been modified to reflect this change. **Exemptions**: The scope of allowable exemptions within R4 (previously R6) is consistent with the regulatory directives of Order No. 901. **Regional Variants**: Additional regional variants; such as by Interconnection may be pursued as needed.

Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	

In some cases, the initial 6-month implementation period to develop a technical rationale for an exemption may be too short. This is attributable to the necessary input from the original OEM and in some cases due to the complexity associated with facilities comprised of new and old equipment. One example where this may exist are plants where a repower project may have taken place that does not replace all inverters. In a case such as this, the new equipment may meet the requirements, but the remaining existing equipment may not. This may require a detailed study to verify compliance, or perhaps instead, require some form of hybrid exemption for the site. Unlike the stated technical goal of the standard where this is a "performance based" standard, the justification for a technical exemption will require some form of a study to justify that exemption. This could lead to a greater than 6-month period in developing the exemption request. To accommodate these situations, AEP recommends an implementation period of 18 months. PRC-029 requires that IBR's shall ride through 110%-120% overvoltage from 0-1 seconds as seen at the high side of the main power step-up transformer. Due to voltage drop, the voltage seen at the equipment terminals can be another 5% higher leading to potential equipment damage from overvoltage. AEP suggests that the SDT consider lowering the ride through to 110% at the high side of the main step-up transformer.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Regarding Exemptions**: The team has modified Requirement R4 (previous R6) to include clarity on allowable exemptions and requires identification of such limitations to be documented and submitted. The Implementation Plan has been modified to 12 months following the effective date of PRC-028. All revisions to Reliability Standards directed by Order 901 must be fully implemented by 2030. **Previous R3**: Previous requirement R3 has been removed. Information on the TOV calculation has been added to Attachment 1.	
Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	2020-02_EPRI Comments on Draft NERC PRC-029 (IBR ride-through) Reliability Standard.pdf
Comment	
Likes 0	
Dislikes 0	

Response
Thank you for your comments. Please see responses herein.

End of Report

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reminder

Standards Announcement

Project 2020-02 Modifications to PRC-024 (Generator Ride-through) | PRC-024-4 and PRC-029-1

Initial Ballots and Non-binding Polls Open through April 22, 2024

Now Available

Initial ballots for **Project 2020-02 Modifications to PRC-024 (Generator Ride-through)** and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Monday, 22, 2024**.

The Standards Committee approved waivers to the Standard Processes Manual at their December 2023 meeting. These waivers were sought by NERC Standards staff for reduced formal comment and ballot periods. This will assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 901. *FERC Order 901 was issued under* Docket No. RM22-12-000 *on October 19, 2023*.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps
The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Manager of Standards Development, Jamie Calderon (via email) or at 404-960-0568 Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2020-02 Modifications to PRC-024 (Generator Ride-through) observer list” in the Titla and Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2020-02 Modifications to PRC-024 (Generator Ride-through) | PRC-024-4 and PRC-029-1

Formal Comment Period Open through April 22, 2024
Ballot Pools Forming through April 5, 2024

Now Available

A 25-day formal comment period for **Project 2020-02 Modifications to PRC-024 (Generator Ride-through)**, is open through **8 p.m. Eastern, Monday, April 22, 2024**.

The Standards Committee approved waivers to the Standard Processes Manual at their December 2023 meeting. These waivers were sought by NERC Standards staff for reduced formal comment and ballot periods. This will assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 901. *FERC Order 901 was issued under* Docket No. RM22-12-000 *on October 19, 2023.*

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Friday, April 5, 2024.** Registered Ballot Body members can join the ballot pools here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*

- *Please be mindful of ballot and comment period closing dates. We ask to* ***allow at least 48 hours*** *for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts* ***prior to the last day*** *of a comment/ballot period.*

Next Steps

Initial ballots for the standards and implementation plan, as well as non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **April 12 - 22, 2024**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Manager of Standards Development, Jamie Calderon (via email) or at 404-960-0568 Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2020-02 Modifications to PRC-024 (Generator Ride-through) observer list" in the Description Box.

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/321)
Ballot Name: 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-024-4 IN 1 ST
Voting Start Date: 4/12/2024 12:01:00 AM
Voting End Date: 4/22/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 248
Total Ballot Pool: 271
Quorum: 91.51
Quorum Established Date: 4/22/2024 3:10:52 PM
Weighted Segment Value: 61.73

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	75	1	38	0.633	22	0.367	0	8	7
Segment: 2	8	0.7	2	0.2	5	0.5	0	0	1
Segment: 3	55	1	30	0.6	20	0.4	0	3	2
Segment: 4	14	1	9	0.9	1	0.1	0	2	2
Segment: 5	68	1	37	0.661	19	0.339	0	6	6
Segment: 6	46	1	20	0.571	15	0.429	1	5	5
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	5	0.4	2	0.2	2	0.2	0	1	0
Totals:	271	6.1	138	3.765	84	2.335	1	25	23

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Negative	Comments Submitted
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Third-Party Comments
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		None	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Salt River Project	Matthew Jaramilla	Israel Perez	Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Negative	Third-Party Comments
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Negative	Third-Party Comments
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		None	N/A
2	California ISO	Darcy O'Connell		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Independent Electricity System Operator	Helen Lainis		Negative	Comments Submitted
2	ISO New England, Inc.	John Pearson		Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Negative	Third-Party Comments
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Tony Hua		Negative	Comments Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		Abstain	N/A
4	Utility Services, Inc.	Carver Powers		None	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	American Municipal Power	Amy Ritts		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Negative	Comments Submitted
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson	David Campbell	None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments
5	PSEG Nuclear LLC	Tim Kucey		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Negative	Comments Submitted
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	Abstain	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	Mathew Miller		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Abstain	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Third-Party Comments
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Great River Energy	Brian Meloy		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Russell Ferrell		Negative	No Comment Submitted
6	Manitoba Hydro	Kelly Bertholet		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Negative	Third-Party Comments
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		None	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tyler Schwendiman		Negative	Comments Submitted
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/321)
Ballot Name: 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-029-1 IN 1 ST
Voting Start Date: 4/12/2024 12:01:00 AM
Voting End Date: 4/22/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 243
Total Ballot Pool: 267
Quorum: 91.01
Quorum Established Date: 4/22/2024 3:13:20 PM
Weighted Segment Value: 25.37

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	74	1	15	0.273	40	0.727	1	11	7
Segment: 2	8	0.6	0	0	6	0.6	0	0	2
Segment: 3	54	1	11	0.224	38	0.776	0	3	2
Segment: 4	14	1	4	0.4	6	0.6	0	2	2
Segment: 5	67	1	16	0.296	38	0.704	0	7	6
Segment: 6	45	1	8	0.229	27	0.771	0	5	5
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	5	0.4	1	0.1	3	0.3	0	1	0
Totals:	267	6	55	1.522	158	4.478	1	29	24

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Negative	Comments Submitted
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Third-Party Comments
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	No Comment Submitted
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Lincoln Electric System	Josh Johnson		Negative	Comments Submitted
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	Comments Submitted
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Negative	Third-Party Comments
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		None	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Salt River Project	Matthew Jaramilla	Israel Perez	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Negative	Third-Party Comments
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Negative	Third-Party Comments
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		None	N/A
2	California ISO	Darcy O'Connell		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	ISO New England, Inc.	John Pearson		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Negative	Third-Party Comments
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Negative	Comments Submitted
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	Comments Submitted
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Negative	Third-Party Comments
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Tony Hua		Negative	Comments Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Third-Party Comments
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Georgia System Operations Corporation	Katrina Lyons		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
4	Oklahoma Municipal Power Authority	Michael Watt		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Ken Habgood		Abstain	N/A
4	Utility Services, Inc.	Carver Powers		None	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	American Municipal Power	Amy Ritts		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Negative	Comments Submitted
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	BC Hydro and Power Authority	Quincy Wang		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Bonneville Power Administration	Juergen Bermejo		Abstain	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Negative	Third-Party Comments
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson	David Campbell	None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Third-Party Comments
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Abstain	N/A
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments
5	PSEG Nuclear LLC	Tim Kucey		Negative	Third-Party Comments
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Negative	Comments Submitted
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	Abstain	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
6	AEP	Mathew Miller		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Abstain	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Third-Party Comments
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		Negative	Comments Submitted
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Russell Ferrell		Negative	Third-Party Comments
6	Manitoba Hydro	Kelly Bertholet		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Abstain	N/A
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Negative	Third-Party Comments
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		None	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tyler Schwendiman		Negative	Comments Submitted
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted

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Showing 1 to 267 of 267 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/321)
Ballot Name: 2020-02 Modifications to PRC-024 (Generator Ride-through) Implementation Plan IN 1 OT
Voting Start Date: 4/12/2024 12:01:00 AM
Voting End Date: 4/22/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 247
Total Ballot Pool: 271
Quorum: 91.14
Quorum Established Date: 4/22/2024 3:12:23 PM
Weighted Segment Value: 37.5

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	75	1	25	0.439	32	0.561	0	11	7
Segment: 2	8	0.5	2	0.2	3	0.3	0	1	2
Segment: 3	55	1	15	0.313	33	0.688	0	5	2
Segment: 4	14	0.8	2	0.2	6	0.6	1	3	2
Segment: 5	68	1	21	0.389	33	0.611	0	9	5
Segment: 6	46	1	10	0.323	21	0.677	0	9	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	5	0.2	2	0.2	0	0	0	3	0
Totals:	271	5.5	77	2.063	128	3.437	1	41	24

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Third-Party Comments
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Negative	Comments Submitted
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		None	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Salt River Project	Matthew Jaramilla	Israel Perez	Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Negative	Third-Party Comments
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Negative	Third-Party Comments
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		None	N/A
2	California ISO	Darcy O'Connell		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A
2	ISO New England, Inc.	John Pearson		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Negative	Comments Submitted
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Negative	Comments Submitted
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Negative	Comments Submitted
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	No Comment Submitted
4	Austin Energy	Tony Hua		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Third-Party Comments
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Georgia System Operations Corporation	Katrina Lyons		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Oklahoma Municipal Power Authority	Michael Watt		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Ken Habgood		Abstain	N/A
4	Utility Services, Inc.	Carver Powers		None	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	American Municipal Power	Amy Ritts		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Bonneville Power Administration	Juergen Bermejo		Abstain	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson	David Campbell	None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Third-Party Comments
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Abstain	N/A
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Negative	Comments Submitted
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	Abstain	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	U.S. Bureau of Reclamation	Wendy Kalidass		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
6	AEP	Mathew Miller		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Abstain	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Third-Party Comments
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Russell Ferrell		Abstain	N/A
6	Manitoba Hydro	Kelly Bertholet		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Abstain	N/A
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		None	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tyler Schwendiman		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/321)
Ballot Name: 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-024-4 | Non-binding Poll IN 1 NB
Voting Start Date: 4/12/2024 12:01:00 AM
Voting End Date: 4/22/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 227
Total Ballot Pool: 254
Quorum: 89.37
Quorum Established Date: 4/22/2024 3:17:32 PM
Weighted Segment Value: 63.79

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	71	1	32	0.681	15	0.319	18	6
Segment: 2	7	0.2	0	0	2	0.2	3	2
Segment: 3	52	1	25	0.595	17	0.405	7	3
Segment: 4	14	0.9	8	0.8	1	0.1	3	2
Segment: 5	63	1	31	0.674	15	0.326	10	7
Segment: 6	42	1	14	0.538	12	0.462	9	7
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0
Segment: 9	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	5	0.2	1	0.1	1	0.1	3	0
Totals:	254	5.3	111	3.388	63	1.912	53	27

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		None	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Matthew Jaramilla	Israel Perez	Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A
2	ISO New England, Inc.	John Pearson		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Tony Hua		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
4	Oklahoma Municipal Power Authority	Michael Watt		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		Abstain	N/A
4	Utility Services, Inc.	Carver Powers		None	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo		Abstain	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson	David Campbell	None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Comments Submitted
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	National Grid USA	Robin Berry		Negative	Comments Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Negative	Comments Submitted
5	Tennessee Valley Authority	Darren Boehm		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	U.S. Bureau of Reclamation	Wendy Kalidass		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Great River Energy	Brian Meloy		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Russell Ferrell		Negative	Comments Submitted
6	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		None	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tyler Schwendiman		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/321)
Ballot Name: 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-029-1 | Non-binding Poll IN 1 NB
Voting Start Date: 4/12/2024 12:01:00 AM
Voting End Date: 4/22/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 222
Total Ballot Pool: 251
Quorum: 88.45
Quorum Established Date: 4/22/2024 3:26:39 PM
Weighted Segment Value: 25.15

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	71	1	12	0.273	32	0.727	20	7
Segment: 2	7	0.2	0	0	2	0.2	3	2
Segment: 3	51	1	10	0.244	31	0.756	7	3
Segment: 4	14	0.9	3	0.3	6	0.6	3	2
Segment: 5	62	1	12	0.273	32	0.727	10	8
Segment: 6	41	1	4	0.16	21	0.84	9	7
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0
Segment: 9	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	5	0.2	1	0.1	1	0.1	3	0
Totals:	251	5.3	42	1.349	125	3.951	55	29

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Comments Submitted
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Negative	Comments Submitted
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	Comments Submitted
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		None	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Salt River Project	Matthew Jaramilla	Israel Perez	Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derdour		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sho-Me Power Electric Cooperative	Olivia Olson		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A
2	ISO New England, Inc.	John Pearson		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Negative	Comments Submitted
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	Comments Submitted
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
4	Austin Energy	Tony Hua		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Georgia System Operations Corporation	Katrina Lyons		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
4	Oklahoma Municipal Power Authority	Michael Watt		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Ken Habgood		Abstain	N/A
4	Utility Services, Inc.	Carver Powers		None	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	BC Hydro and Power Authority	Quincy Wang		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo		None	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Decatur Energy Center LLC	Megan Melham		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson	David Campbell	None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		Negative	Comments Submitted
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Comments Submitted
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		Abstain	N/A
5	National Grid USA	Robin Berry		Negative	Comments Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Comments Submitted
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Negative	Comments Submitted
5	Tennessee Valley Authority	Darren Boehm		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		Negative	Comments Submitted
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Russell Ferrell		Negative	Comments Submitted
6	Muscatine Power and Water	Nicholas Burns		Abstain	N/A
6	New York Power Authority	Shelly Dineen		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Abstain	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		None	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tyler Schwendiman		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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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

Draft 2 of PRC-024-4 is posted for a 15-day formal comment period with additional ballot.

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023
25-day formal comment period with initial ballot	March 27 - April 22, 2024

Anticipated Actions	Date
15-day formal comment period and additional ballot	June 18 – July 8, 2024
Final Ballot	July 15 – July 19, 2024
Board Adoption	August 14, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

A. Introduction

1. **Title:** **Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and Type 2 Wind Resources, and Synchronous Condensers**

2. **Number:** **PRC-024-4**

3. **Purpose:** To assure that protection of synchronous generators, type 1 and type 2 wind resources, and synchronous condensers do not cause tripping during defined frequency and voltage excursions in support of the Bulk Power System (BPS).

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Generator Owners that apply protection listed in Sections 4.2.1 or 4.2.2.

4.1.2. Transmission Owners that apply protection listed in Section 4.2.2.

4.1.3. 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.

4.1.4. 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 trip; and are applied to the following:

4.2.1.1 Bulk Electric System (BES) synchronous generators.

4.2.1.2 BES GSU transformer(s) for synchronous generators.

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

4.2.1.4 Individual dispersed power producing type 1 or type 2 wind resource(s) identified in the BES Definition, Inclusion I4.

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[1] For the purpose of this standard, the MPT is the power transformer that steps up voltage from multiple small synchronous generators (e.g. multiple small hydro generators connecting to a common bus) or from a type 1 or type 2 wind resource collector station to transmission voltage .

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

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

4.2.1.5 Elements that are designed primarily for the delivery of capacity from multiple synchronous generators connecting to a common bus or individual dispersed power producing type 1 or type 2 wind resources identified in the BES Definition, Inclusion I4, to the point where those resources aggregate to greater than 75 MVA.

4.2.1.6 MPT of multiple synchronous generators connecting to a common bus or MPT of individual dispersed power producing type 1 or type 2 wind resources as identified in the BES Definition, Inclusion I4.

4.2.2 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 transmission connected synchronous condensers; or (ii) provide signals to trip transmission connected synchronous condenser and are applied to the following:

4.2.2.1 BES synchronous condensers

4.2.2.2 BES step-up transformer(s) for synchronous condensers.

4.2.2.3 High-side of the synchronous condenser-connected unit auxiliary transformer (UAT).

4.2.3 **Exemptions:** Protection on all auxiliary equipment within the synchronous generator, type 1 or type 2 wind resource, or synchronous condenser Facility.

5. **Effective Date:** See Implementation Plan for PRC-024-4

B. Requirements and Measures

R1. Each Generator Owner and Transmission Owner shall set applicable frequency protection[4] in accordance with PRC-024-4 Attachment 1 such that the applicable protection does not cause the Facility to which it is applied to trip within the "no trip zone" during a frequency excursion with the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Applicable frequency protection may be set to trip within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M1. Each Generator Owner and Transmission Owner shall have evidence that the applicable frequency protection has been set in accordance with Requirement R1, such as dated setting sheets, calibration sheets, calculations, or other documentation.

R2. Each Generator Owner and Transmission Owner shall set applicable voltage protection[5] in accordance with PRC-024-4 Attachment 2, such that the applicable protection does not cause the Facility to which it is applied trip within the "no trip zone" during a voltage excursion at the high-side of the GSU or MPT, 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-024-4 Attachment 2, then the Generator Owner or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- Applicable voltage protection may be set to trip during a voltage excursion within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M2. 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.

R3. Each Generator Owner and Transmission Owner shall document each known regulatory or equipment limitation[6] that prevents an its synchronous generator, type 1 or type 2 wind resource, or synchronous condenser, with applicable frequency or voltage protection from meeting the protection setting criteria in Requirements R1 or R2, including (but not limited to) study results, experience from an actual event, or

[4] 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 synchronous generator(s), type 1 or type 2 wind resource(s), or synchronous condenser(s); or (ii) provide signals to same to trip.
[5] Ibid.
[6] Excludes limitations caused by the setting capability of the frequency, voltage, and volts per hertz protective relays applied to the synchronous generator(s), type 1 and type 2 wind resource(s), and condenser(s). This does not exclude limitations originating in the equipment protected by the relay(s).

manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner and Transmission 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 and Transmission Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations 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.

R4. Each Generator Owner and Transmission Owner shall provide its applicable protection settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated Facility 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 settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of protection setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Generator Owner and Transmission Owner shall have evidence that it communicated applicable 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.

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.

   1.2. **Evidence Retention:** 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 and Transmission Owner shall keep data or evidence of Requirements R1 through R4 for five years or until the next audit, whichever is longer.
   - If a Generator Owner or Transmission 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.

   1.3. **Compliance Monitoring and Enforcement 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.

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 or Transmission Owner failed to set its applicable frequency protection so that it does not trip according to Requirement R1.
R2.	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 according to Requirement R2.
R3.	The Generator Owner or Transmission 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 or Transmission 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 or Transmission 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 or Transmission 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 or Transmission Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				days of identifying the limitation.
R4.	The Generator Owner or Transmission Owner provided its protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner or provided protection settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner or Transmission Owner failed to provide its protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner failed to provide protection settings within 150 calendar days of a written request.

D. Regional Variances

D.A. Variance for the Quebec Interconnection

This Variance 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.

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

D.A.2. Each Generator Owner and Transmission Owner shall set applicable voltage protection[7] in accordance with PRC-024 Attachment 2B, such that the applicable protection does not cause the Facility to which it is applied to trip within the “no trip zone” during a voltage excursion 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”.
- Applicable voltage protection may be set to trip during a voltage excursion within a portion of the “no trip zone” of PRC-024 Attachment 2B 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 2B, then the Generator Owner or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner’s study.

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 2B and notify, within 30 calendar days of its designation,

[7] 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 synchronous generator(s), type 1 or type 2 wind resource(s), or synchronous condenser(s); or (ii) provide signals to same to trip.

each Generator Owner or Transmission Owner that owns facilities[8] 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.

[8] Facilities in the strategic power plants include facilities with synchronous generator(s) 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 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 facilities in the strategic power plants between 31 days and 45 days after its designation.	The Planning Coordinator designated strategic power plants at least once every five calendar years but notified each Generator Owner or Transmission Owner that owns facilities in the strategic power plants between 46 days and 60 days after its designation.	The Planning Coordinator failed to designate, at least once every five years, the strategic power plants that must comply with Attachment 2B. 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 its designation.

E. Associated Documents

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	February 6, 2020	Adopted by the NERC Board of Trustees	Standard revised in Project 2018-04
3	July 9, 2020	FERC Letter Order approved PRC024-3. Docket No. RD20-7-000	
3	July 17, 2020	Effective Date	10/1/2022
4	TBD	Revisions made by the 2020-02 Drafting Team	Revision

Attachment 1

(Frequency No Trip Boundaries by Interconnection[9])

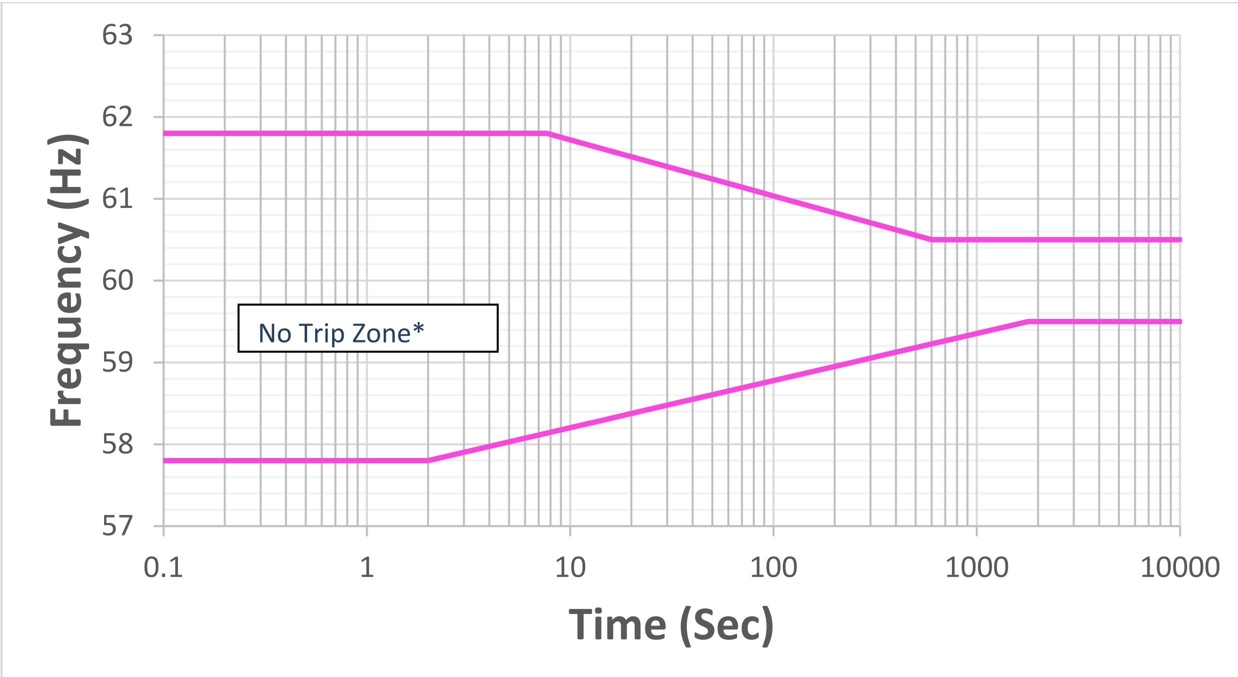

Figure 1: Eastern Interconnection Boundaries

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

Table 1: 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[10]	≤57.8	Instantaneous[11]
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

[9] 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.

[10] 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.

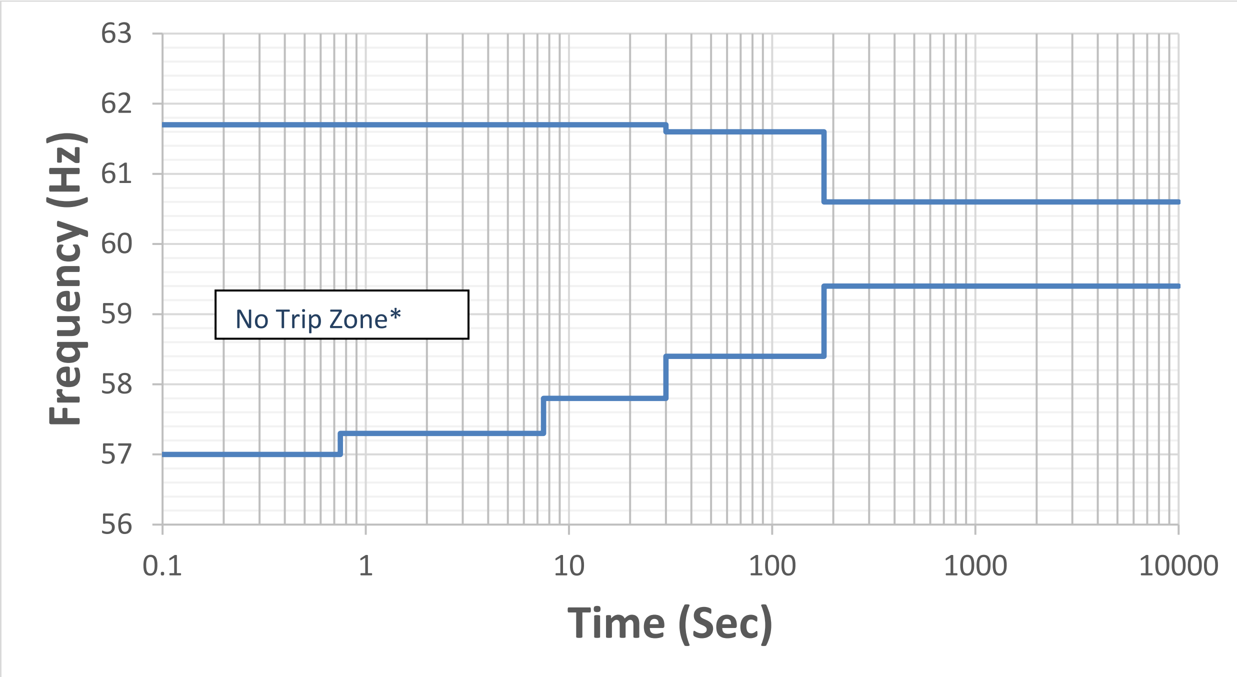

Figure 2: Western Interconnection Boundaries

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

Table 2: 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[11]	≤57.0	Instantaneous[11]
≥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

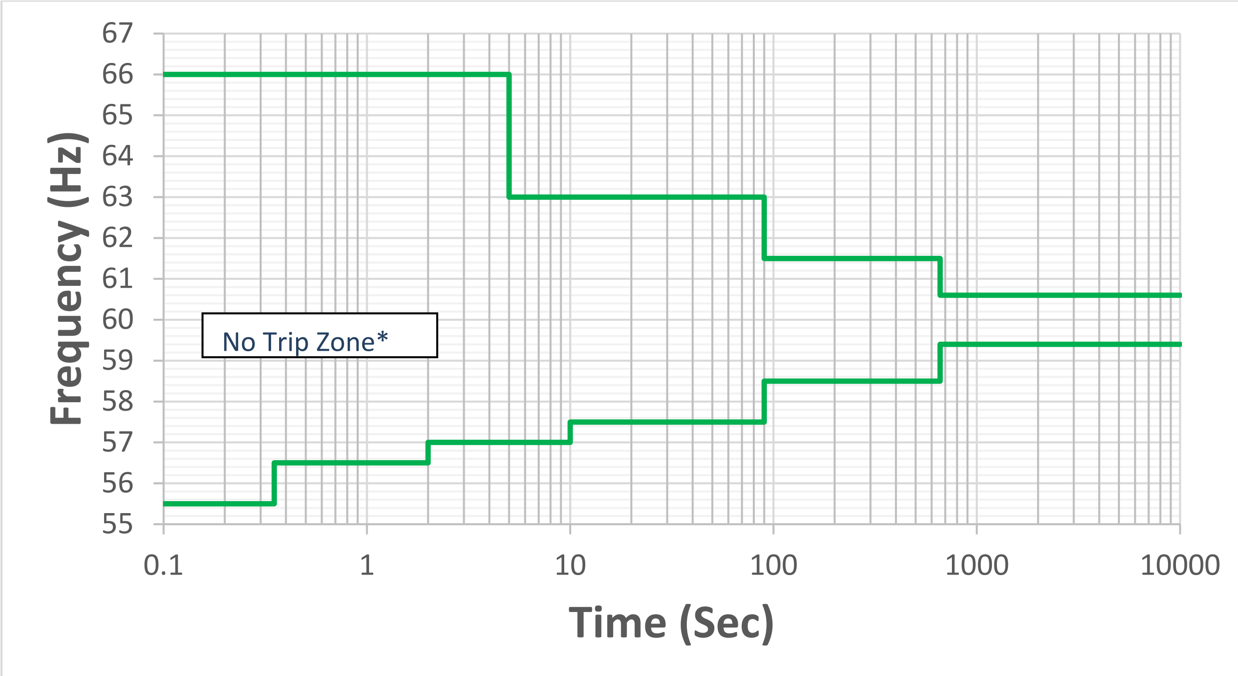

Figure 3: Quebec Interconnection Boundaries

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

Table 3: 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[11]	<55.5	Instantaneous[11]
≥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

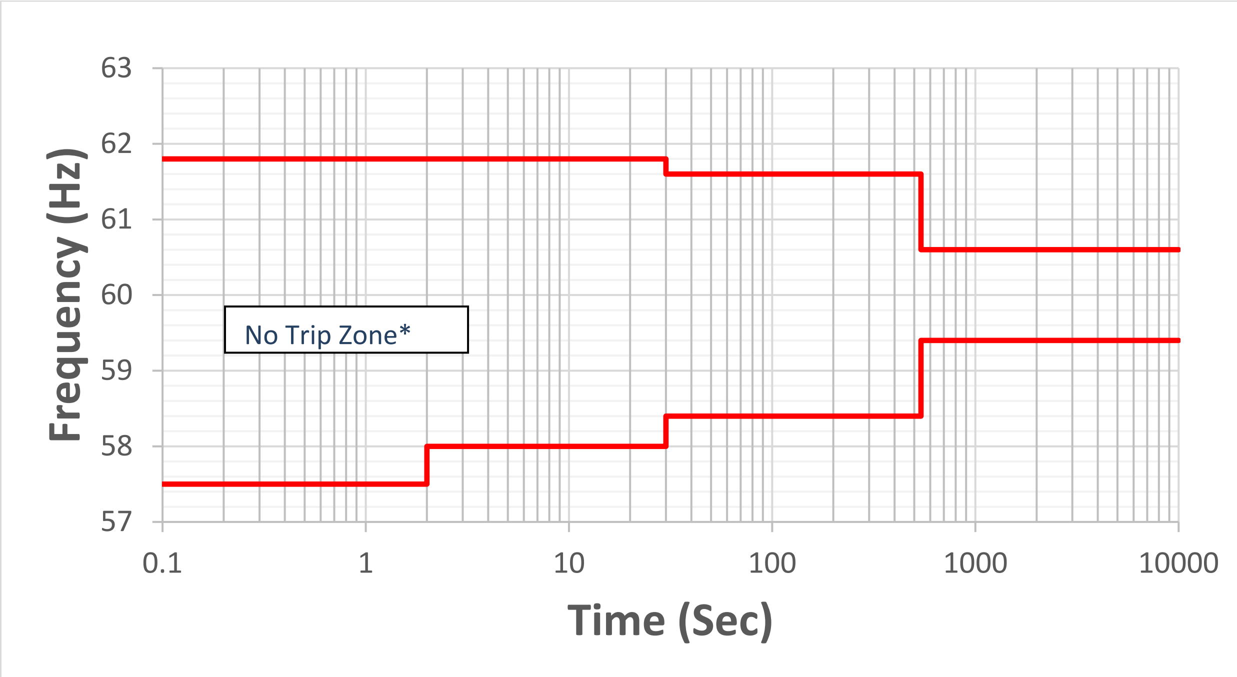

Figure 4: ERCOT Interconnection Boundaries

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

Table 4: 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[11]	≤57.5	Instantaneous[11]
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024 — Attachment 2

(Voltage No-Trip Boundaries – Eastern, Western, and ERCOT Interconnections)

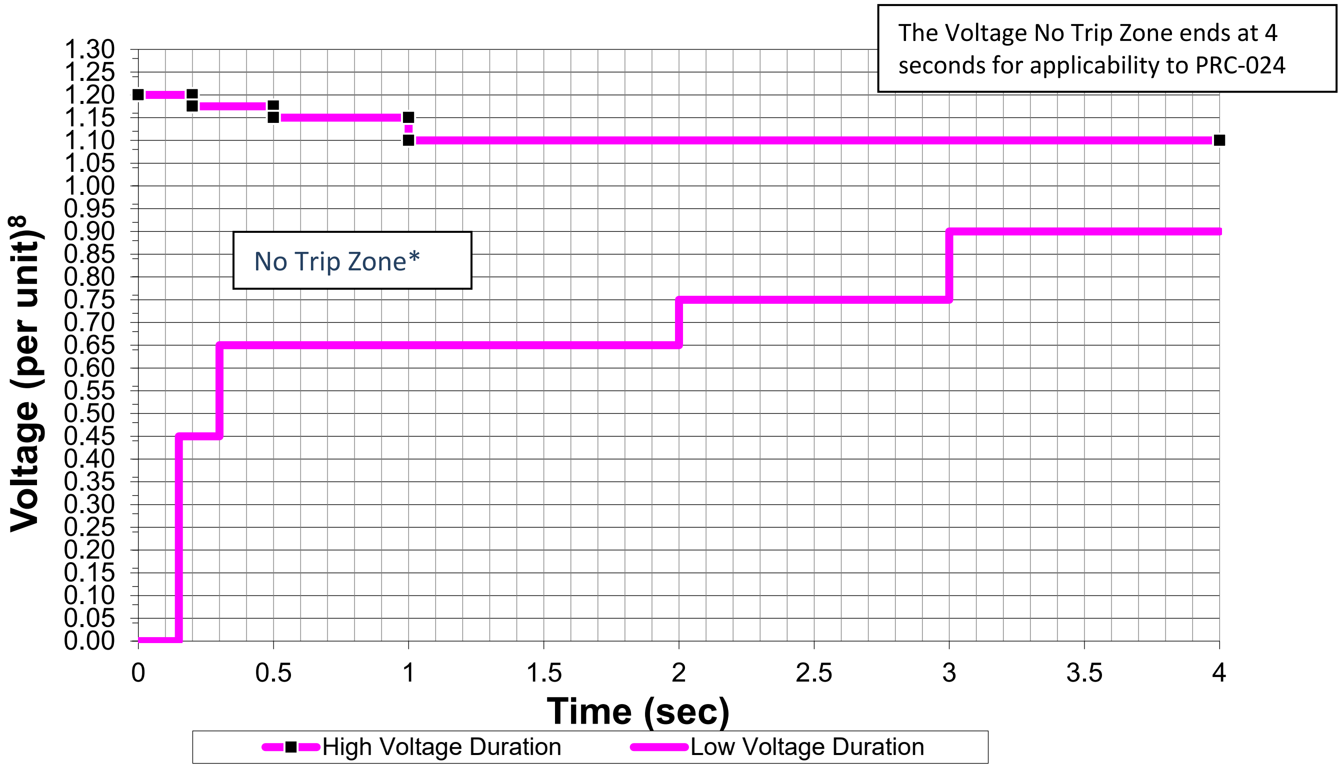

Figure 5: Voltage No-Trip Boundaries – Eastern, Western, and ERCOT Interconnections

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

Table 5: Voltage Boundary Data Points

High Voltage Duration		Low Voltage Duration	
Voltage (per unit)	Minimum Time (sec)	Voltage (per unit)	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

Attachment 2A: Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections

Boundary Details:

1. Unless otherwise specified by the Transmission Planner, the per unit voltage base for these boundaries is the nominal transmission system voltage (e.g., 100 kV, 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 400 kV, 500 kV, 765 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 boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase per unit voltage.
5. For applicability to PRC-024, the “no trip zone” ends at 4 seconds.

Evaluating Protection Settings:

The voltage values in the Attachment 2 voltage boundaries are voltages at the high-side of the GSU/MPT. For 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 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.

PRC-024— Attachment 2B

(Voltage No-Trip Boundaries – Quebec Interconnection)

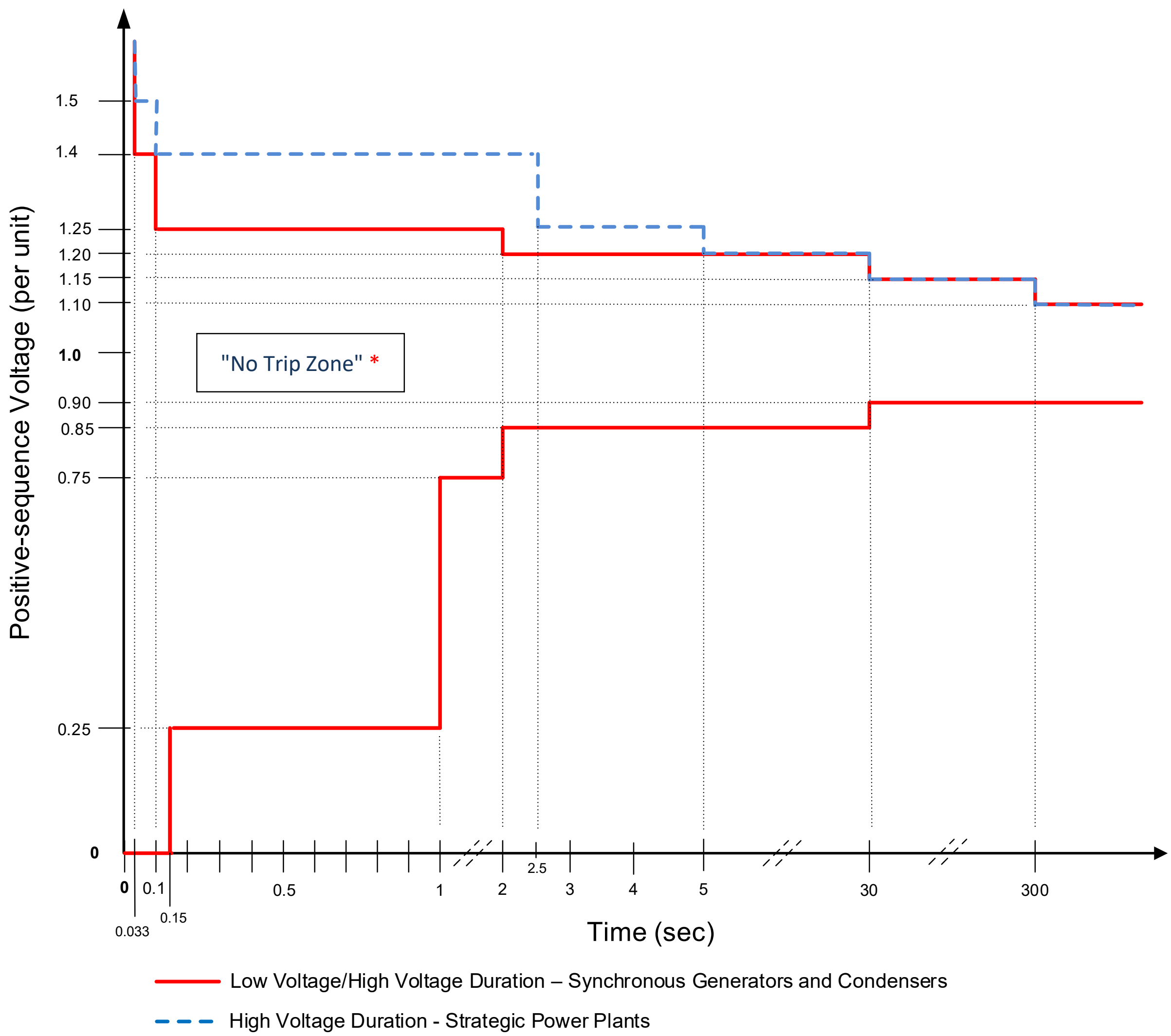

Figure 6: Voltage No-Trip Boundaries – Quebec Interconnection

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

Table 6: High Voltage Boundary Data Points – Quebec Interconnection

High Voltage Duration for all Synchronous Generators and Condensers		High Voltage Duration for strategic Power Plants	
Voltage (per unit)	Minimum Time (sec)	Voltage (per unit)	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 7: Low Voltage Boundary Data Points – Quebec Interconnection

Low Voltage Duration for all Synchronous Generators and Condensers	
Voltage (per unit)	Minimum Time (sec)
<0.25	0.15
<0.75	1.00
<0.85	2.00
<0.90	30
≥0.90	continuous

Attachment 2C: 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 2B voltage boundaries are voltages at the high-side of the GSU/MPT. For 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.

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

Draft 2 of PRC-024-4 is posted for a 15-day formal comment period with additional ballot.

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023
25-day formal comment period with initial ballot	March 27 - April 22, 2024

Anticipated Actions	Date
15-day formal comment period and additional ballot	June 18 – July 8, 2024
Final Ballot	July 15 – July 19, 2024
Board Adoption	August 14, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

A. Introduction

1. **Title:** **Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and Type 2 Wind Resources, and Synchronous Condensers**

2. **Number:** **PRC-024-4**

3. **Purpose:** To assure that protection of synchronous generators, type 1 and type 2 wind resources, and synchronous condensers do not cause tripping during defined frequency and voltage excursions in support of the Bulk Power System (BPS).

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Generator Owners that apply protection listed in Sections 4.2.1 or 4.2.2.

4.1.2. Transmission Owners that apply protection listed in Section 4.2.2.

4.1.3. 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.

4.1.4. 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 -trip; and are applied to the following:

4.2.1.1 Bulk Electric System (BES) synchronous generators.

4.2.1.2 BES GSU transformer(s) for synchronous generators.

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

4.2.1.4 Individual dispersed power producing type 1 or type 2 wind resource(s) identified in the BES Definition, Inclusion I4.

[1] For the purpose of this standard, the MPT is the power transformer that steps up voltage from multiple small synchronous generators~~,~~ (e.g. multiple small hydro generators connecting to a common bus) or from a type 1 or type 2 wind resource collector station to transmission voltage .

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

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

~~4.2.1.4~~4.2.1.5 Elements that are designed primarily for the delivery of capacity from multiple synchronous generators connecting to a common bus or individual dispersed power producing type 1 or type 2 wind resources identified in the BES Definition, Inclusion I4, to the point where those resources aggregate to greater than 75 MVA.

~~4.2.1.5~~4.2.1.6 MPT of multiple synchronous generators connecting to a common bus or MPT of individual dispersed power producing type 1 or type 2 wind resources as identified in the BES Definition, Inclusion I4.

4.2.2 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 transmission connected synchronous condensers; or (ii) provide signals to trip transmission connected synchronous condenser and are applied to the following:

4.2.2.1 BES synchronous condensers

4.2.2.2 BES step-up transformer(s) for synchronous condensers.

4.2.2.3 High-side of the synchronous condenser-connected unit auxiliary transformer (UAT).

4.2.3 **Exemptions:** Protection on all auxiliary equipment within the synchronous generator, type 1 or type 2 wind resource, or synchronous condenser Facility.

5. **Effective Date:** See Implementation Plan for PRC-024-4

B. Requirements and Measures

R1. Each Generator Owner and Transmission Owner shall set applicable frequency protection[4] in accordance with PRC-024-4 Attachment 1 such that the applicable protection does not cause the ~~synchronous generator(s) or condenser(s)~~Facility to which it is applied to trip within the "no trip zone" during a frequency excursion with the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Applicable frequency protection may be set to trip within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M1. Each Generator Owner and Transmission Owner shall have evidence that the applicable frequency protection has been set in accordance with Requirement R1, such as dated setting sheets, calibration sheets, calculations, or other documentation.

R2. Each Generator Owner and Transmission Owner shall set applicable voltage protection[5] in accordance with PRC-024-4 Attachment 2, such that the applicable protection does not cause the ~~synchronous generator(s) or condenser(s)~~Facility to which it is applied trip within the "no trip zone" during a voltage excursion at the high-side of the GSU or MPT, 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-024-4 Attachment 2, then the Generator Owner or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- Applicable voltage protection may be set to trip during a voltage excursion within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M2. 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.

R3. Each Generator Owner and Transmission Owner shall document each known regulatory or equipment limitation[6] that prevents an ~~applicable~~its synchronous generator~~(s)~~, type 1 or type 2 wind resource, or synchronous condenser~~(s)~~, with applicable frequency or voltage protection from meeting the protection setting criteria in Requirements R1 or R2, including (but not limited to) study results,

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[4] 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 synchronous generator(s~~)~~), type 1 or type 2 wind resource(s), or synchronous condenser(s); or (ii) provide signals to ~~the synchronous generator(s) or condenser(s)~~same to trip.

[5] Ibid.

[6] Excludes limitations caused by the setting capability of the frequency, voltage, and volts per hertz protective relays ~~for~~applied to the synchronous generator(s~~) or~~), type 1 and type 2 wind resource(s), and condenser(s). This does not exclude limitations originating in the equipment protected by the relay~~.~~(s).

experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner and Transmission 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 and Transmission Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations 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.

R4. Each Generator Owner and Transmission Owner shall provide its applicable protection settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated ~~synchronous generator(s) or condenser(s)~~Facility 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 settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of protection setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Generator Owner and Transmission Owner shall have evidence that it communicated applicable 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.

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.

1.2. Evidence Retention: 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 and Transmission Owner shall keep data or evidence of Requirements R1 through R4 for five years or until the next audit, whichever is longer.
- If a Generator Owner or Transmission 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.

1.3. Compliance Monitoring and Enforcement 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.

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 or Transmission Owner failed to set its applicable frequency protection so that it does not trip according to Requirement R1.
R2.	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 according to Requirement R2.
R3.	The Generator Owner or Transmission 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 or Transmission 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 or Transmission 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 or Transmission 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 or Transmission Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				days of identifying the limitation.
R4.	The Generator Owner or Transmission Owner- provided its protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner or Transmission Owner- provided its protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner or provided protection settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner or Transmission Owner- failed to provide its protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner failed to provide protection settings within 150 calendar days of a written request.

D. Regional Variances

D.A. Variance for the Quebec Interconnection

This Variance 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.

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

D.A.2. Each Generator Owner and Transmission Owner shall set applicable voltage protection[~~6~~7] in accordance with PRC-024 Attachment 2B, such that the applicable protection does not cause the ~~synchronous generator(s) or condenser(s)~~Facility to which it is applied to trip ~~-~~within the "no trip zone" during a voltage excursion 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".
- ~~Synchronous generator(s) are permitted to~~Applicable voltage protection may be set to trip during a voltage excursion ~~bounded by~~within a portion of the "no trip zone" of PRC-024 Attachment 2B 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 2B, then the Generator Owner or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.

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

[7] 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 synchronous generator(s), type 1 or type 2 wind resource(s), or synchronous condenser(s); or (ii) provide signals to same to trip.

Attachment 2B and notify, within 30 calendar days of its designation, each Generator Owner or Transmission Owner that owns facilities[8] 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.

[8] Facilities in the strategic power plants include facilities with synchronous generator(s) 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 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 facilities in the strategic power plants between 31 days and 45 days after its designation.	The Planning Coordinator designated strategic power plants at least once every five calendar years but notified each Generator Owner or Transmission Owner that owns facilities in the strategic power plants between 46 days and 60 days after its designation.	The Planning Coordinator failed to designate, at least once every five years, the strategic power plants that must comply with Attachment 2B. 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 its designation.

E. Associated Documents

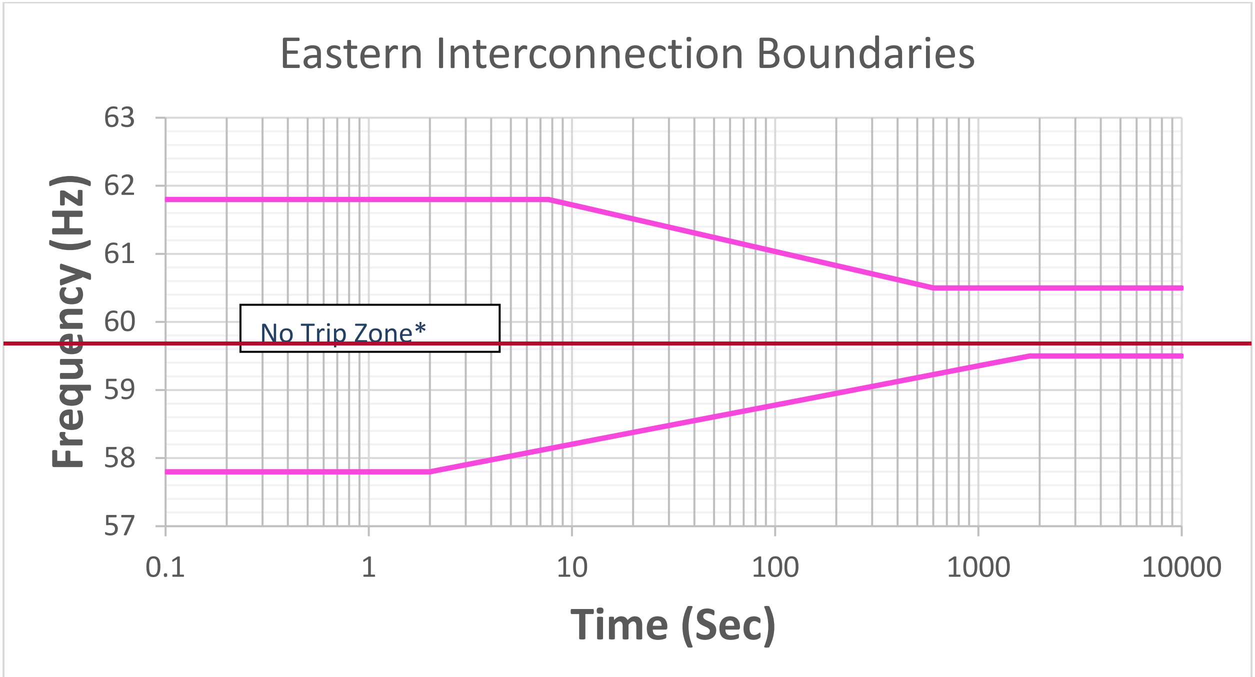
Implementation Plan

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	February 6, 2020	Adopted by the NERC Board of Trustees	Standard revised in Project 2018-04
3	July 9, 2020	FERC Letter Order approved PRC~~-~~-024~~-~~-3. Docket No. RD20-7-000	
3	July 17, 2020	Effective Date	10/1/2022
4	TBD	Revisions made by the 2020-02 Drafting Team	Revision

Attachment 1

(Frequency No Trip Boundaries by Interconnection[9])



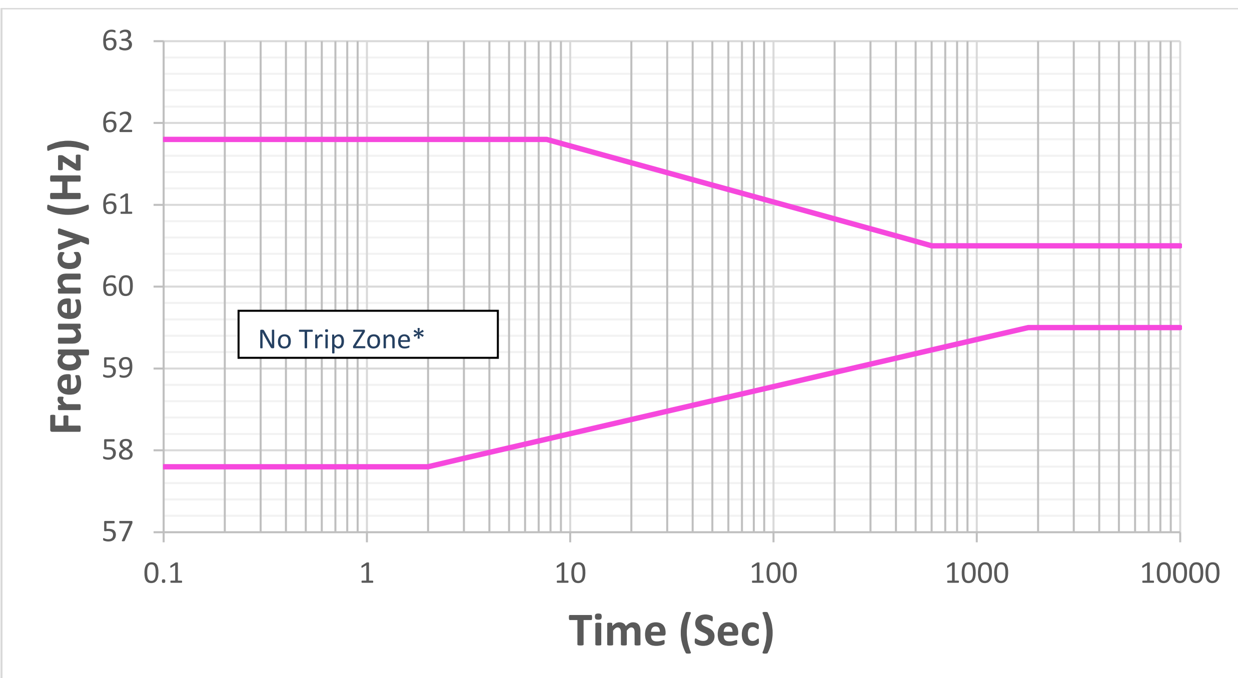


Figure 1~~1.1~~

: Eastern Interconnection Boundaries

[9] 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.

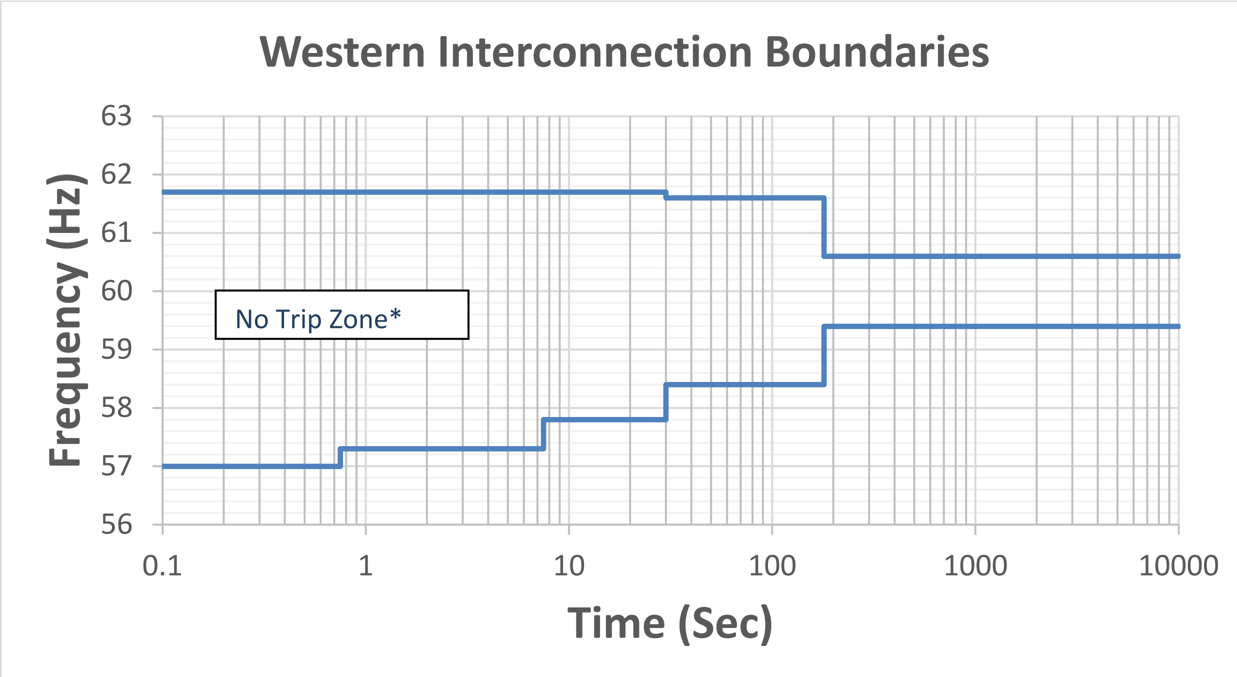
***** The area outside the "No Trip Zone" is not a "Must Trip Zone."***

Table 1: 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[10]	≤57.8	Instantaneous[11]
≥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 1.2~~

[10] 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.



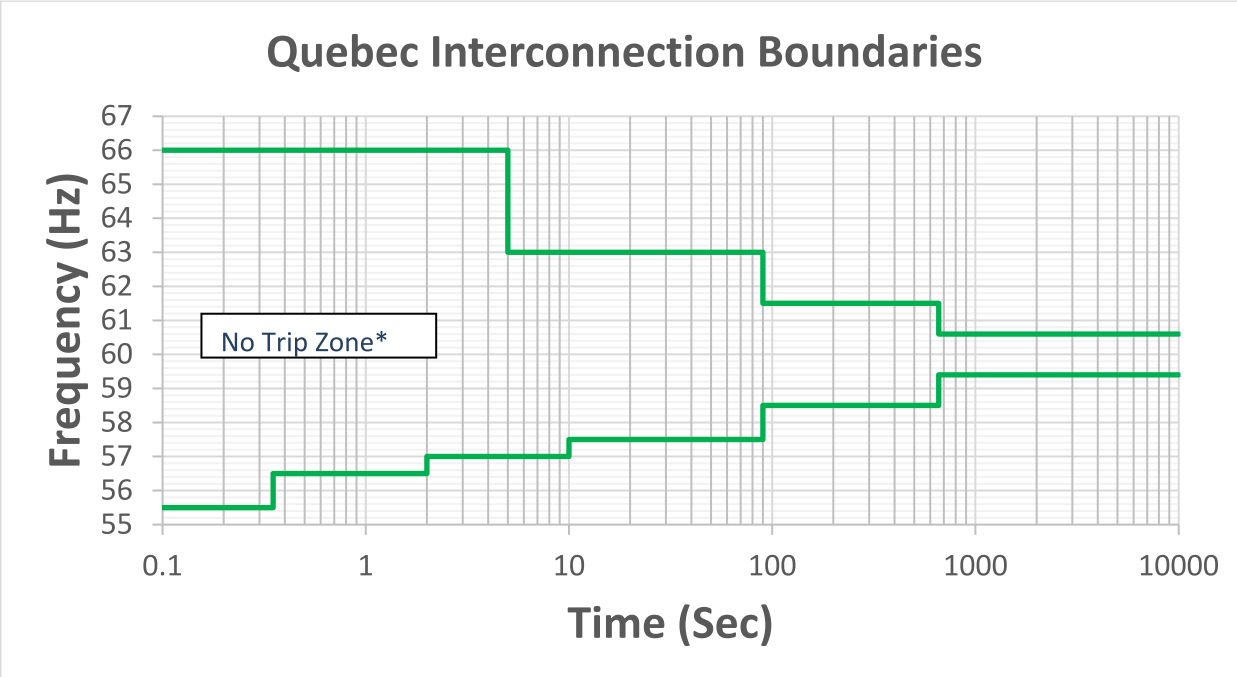
~~Figure1.3~~ Figure 2: Western Interconnection Boundaries

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

Table 2: 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[11]	≤57.0	Instantaneous[11]
≥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 1.4~~



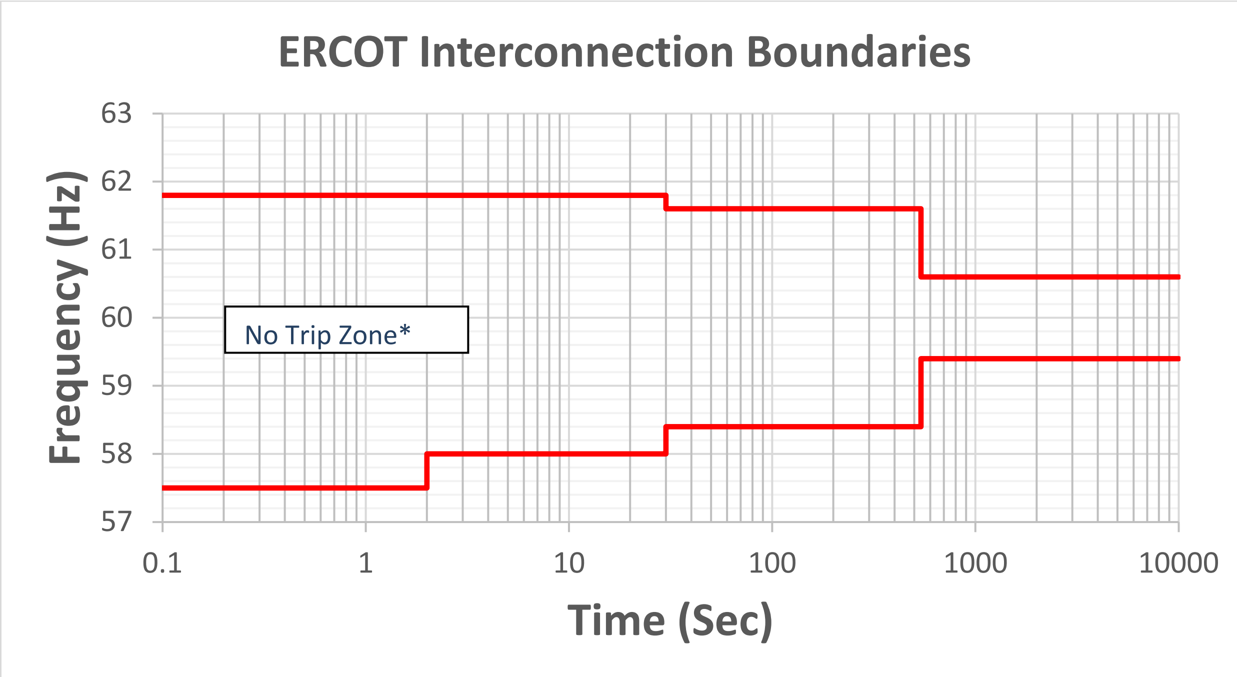
~~Figure 1.5~~ Figure 3: Quebec Interconnection Boundaries

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

Table 3: 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[11]	<55.5	Instantaneous[11]
≥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 1.6~~



~~Figure 1.7~~ Figure 4: ERCOT Interconnection Boundaries

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

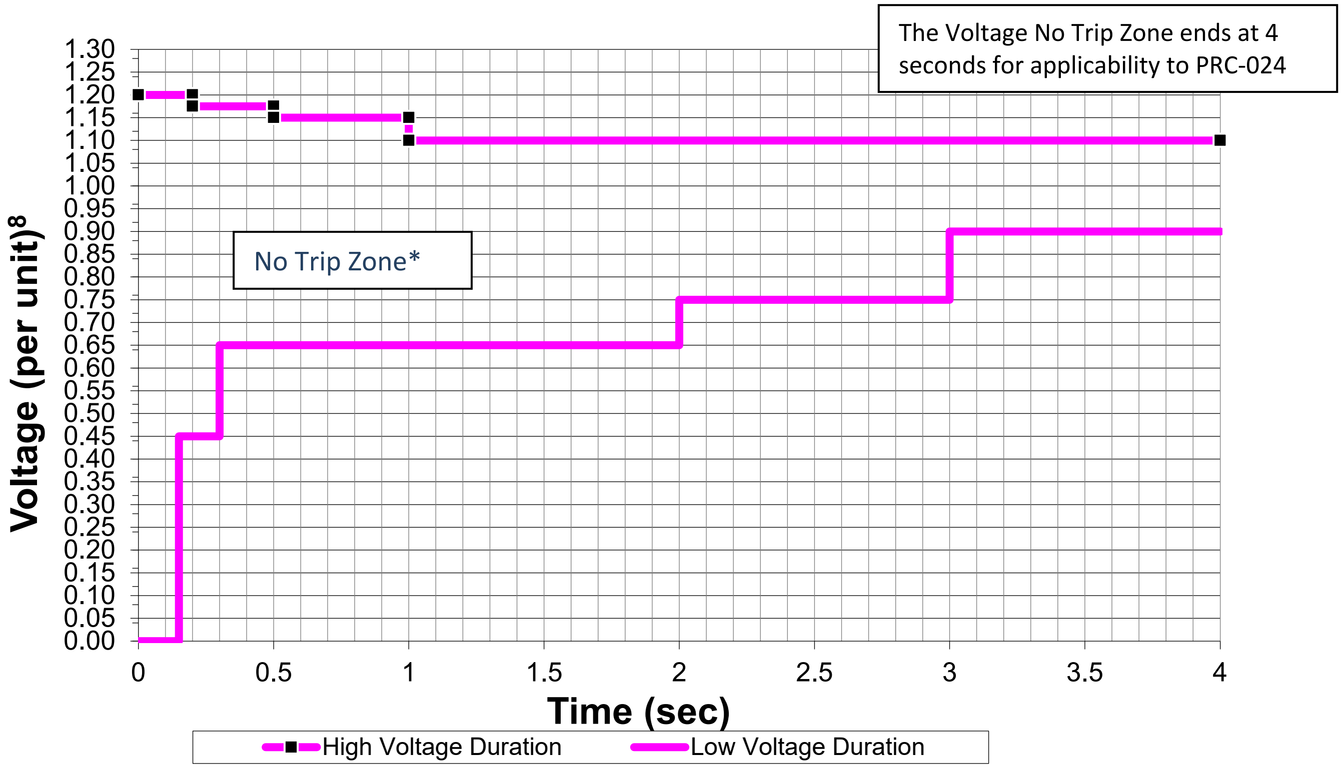
Table 4: Frequency Boundary Data Points – ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (sec)
≥61.8	Instantaneous[11]	≤57.5	Instantaneous[11]
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

~~Table 1.8~~

PRC-024 — Attachment 2

(Voltage No-Trip Boundaries – Eastern, Western, and ERCOT Interconnections)



~~Figure 2.1~~ **Figure 5: Voltage No-Trip Boundaries – Eastern, Western, and ERCOT Interconnections**

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

Table 5: Voltage Boundary Data Points

High Voltage Duration		Low Voltage Duration	
Voltage (per unit)	Minimum Time (sec)	Voltage (per unit)	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 2.2~~

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

Attachment 2A: Voltage Boundary Clarifications ~~(~~ – Eastern, Western, and ERCOT Interconnections~~)~~

Boundary Details:

1. Unless otherwise specified by the Transmission Planner, the per unit voltage base for these boundaries is the nominal transmission system voltage (e.g., 100 kV, 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 400 kV, 500 kV, 765 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 boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase per unit voltage.
5. For applicability to PRC-024, the "no trip zone" ends at 4 seconds.

Evaluating Protection Settings:

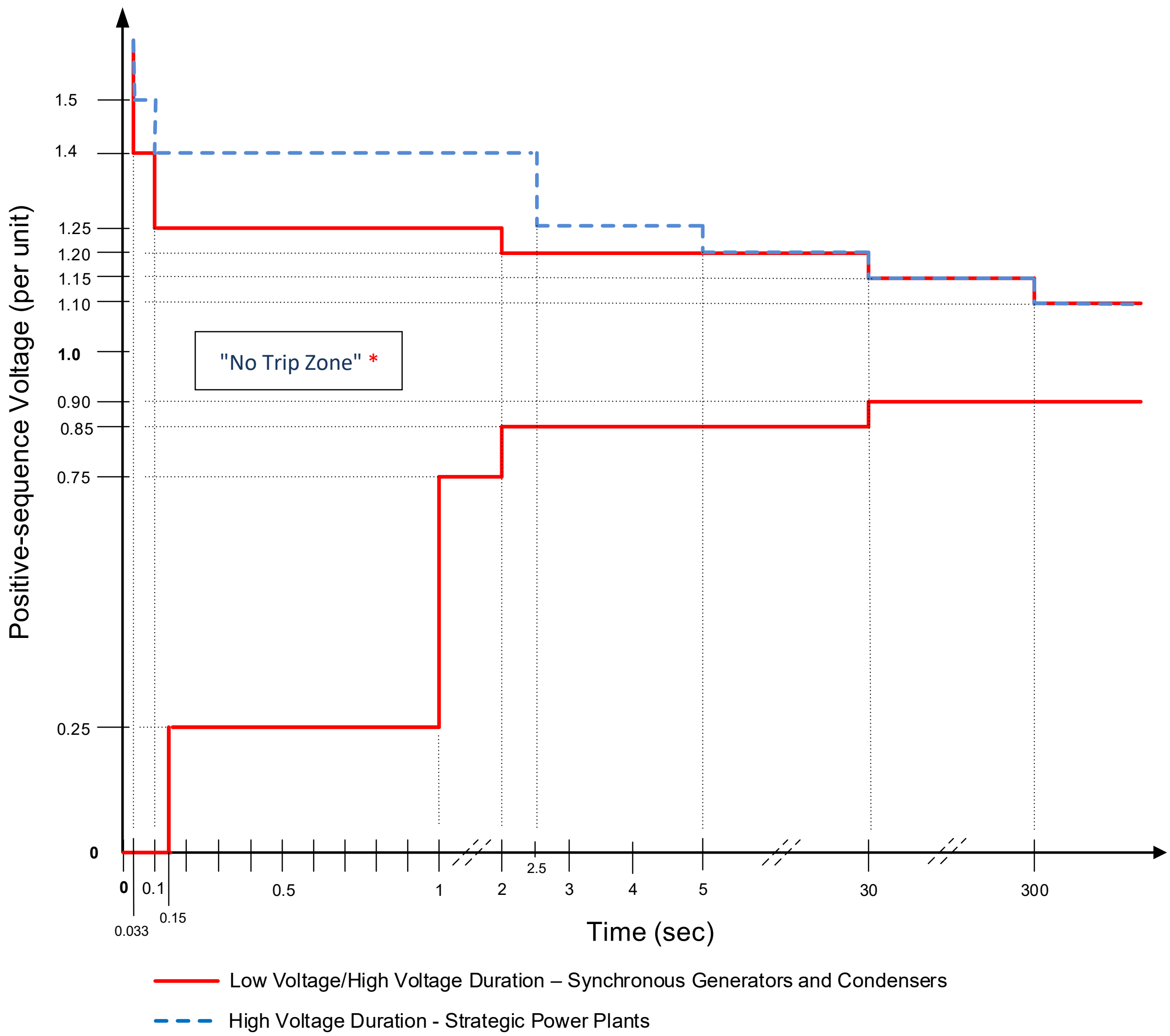
The voltage values in the Attachment 2 voltage boundaries are voltages at the high-side of the GSU/MPT. For resources with multiple stages of step up to reach interconnecting voltage, this is the high-side of the transformer with a low side below 100kV and a high-side 100kV or above**.** When evaluating 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 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.

PRC-024— Attachment 2B

(Voltage No-Trip Boundaries – Quebec Interconnection)



~~Figure 1~~ Figure 6: Voltage No-Trip Boundaries – Quebec Interconnection

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

Table 6: High Voltage Boundary Data Points – Quebec Interconnection

High Voltage Duration for all Synchronous Generators and Condensers		High Voltage Duration for strategic~~1~~ Power Plants	
Voltage (per unit)	Minimum Time (sec)	Voltage (per unit)	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~~

Table 7: Low Voltage Boundary Data Points – Quebec Interconnection

Low Voltage Duration for all Synchronous Generators and Condensers	
Voltage (per unit)	Minimum Time (sec)
<0.25	0.15
<0.75	1.00
<0.85	2.00
<0.90	30
≥0.90	continuous

~~Table 2~~

Attachment 2C
~~(~~: 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 2B voltage boundaries are voltages at the high-side of the GSU/MPT. For 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.

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

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023
Initial 25-day formal comment period and additional ballot	March 27 – April 21, 2024

Anticipated Actions	Date
15-day formal comment period and additional ballot	June 18 – July 8, 2024
Final Ballot	July 16 - 20, 2024
Board adoption	August 14, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Ride-through: Remaining connected, synchronized with the Transmission System, and continuing to operate in response to System conditions through the time-frame of a System Disturbance.

A. Introduction

1. **Title:** **Frequency and Voltage Ride-through Requirements for Inverter-Based Resources**
2. **Number:** **PRC-029-1**
3. **Purpose:** To ensure that Inverter-Based Resources (IBRs) adhere to Ride-through requirements as expected to support the Bulk Power System (BPS) during and after defined frequency and voltage excursions.
4. **Applicability:**

    4.1 Functional Entities:

    4.1.1. Generator Owner

    4.1.2. Transmission Owner[1]

    4.2 Facilities:

    4.2.1. BES inverter-based resources[2]

    4.2.2. IBR Registration Criteria

Effective Date: See Implementation Plan for Project 2020-02 – PRC-029-1

Standard-Only Definition: None

[1] For owners of Voltage Source Converter – High-voltage Direct Current (VSC-HVDC) transmission facilities that are dedicated connections for IBR to the BPS

[2] For the purpose of this standard, "inverter-based resources" refers to a collection of individual solar photovoltaic (PV), Type 3 and Type 4 wind turbines, battery energy storage system (BESS), or fuel cells that operate as a single plant/resource. In case of offshore wind plants connecting via a dedicated VSC-HVDC, the inverter-based resource includes the VSC-HVDC system.

B. Requirements and Measures

R1. Each Generator Owner or Transmission Owner shall ensure the design and operation is such that each facility adheres to Ride-through requirements, in accordance with the “must Ride-through[3] zone” as specified in Attachment 1, except for the following: *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

- The facility needed to electrically disconnect in order to clear a fault;
- A documented equipment limitation exists in accordance with Requirement R4; or
- The instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer and is initiated by a non-fault switching event on the transmission system; or
- The Volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

M1. Each Generator Owner and Transmission Owner have evidence of dynamic simulations, studies, or other evidence to demonstrate the design of each facility will adhere to Ride-through requirements, as specified in Requirement R1. Each Generator Owner and Transmission Owner have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) to demonstrate that the operation of each facility did adhere to Ride-through requirements, as specified in Requirement R1. If the Generator Owner and Transmission Owner choose to utilize Ride-through exemptions that occur within the “must Ride-through zone” and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner and Transmission Owner also have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate that the facility failed to Ride-through during a phase jump of greater than or equal to 25 electrical degrees, and documentation from their Transmission Planner, Reliability Coordinator, Planning Coordinator, or Transmission Operator that a non-fault initiated switching event occurred.

R2. Each Generator Owner or Transmission Owner shall ensure the design and operation is such that the voltage performance for each facility adheres to the following during a voltage excursion, unless a documented equipment limitation exists in accordance with Requirement R4. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

[3] Includes no tripping associated with phase lock loop loss of synchronism

2.1. While the voltage at the high-side of the main power transformer[4] remains within the continuous operation region as specified in Attachment 1, each facility shall:

2.1.1 Continue to deliver the pre-disturbance level of active power or available active power, whichever is less.[5]

2.1.2 Continue to deliver reactive power up to its reactive power limit and according to its controller settings.

2.1.3 If the facility cannot deliver both active and reactive power due to a current limit or reactive power limit, when the voltage is below 95 per unit and still within the continuous operation region, then preference shall be given to active or reactive power according to requirements if required by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.2. While voltage at the high-side of the main power transformer is within the mandatory operation region as specified in Attachment 1, each IBR shall exchange current, up to the maximum capability to provide voltage support, on the affected phases during both symmetrical and asymmetrical voltage disturbances, either under[6]:

- Reactive power priority by default; or
- Active power priority if required by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.3. While voltage at the high-side of the main power transformer is within the permissive operation region, as specified in Attachment 1, each facility may operate in current block mode if necessary to avoid tripping. Otherwise, each facility shall follow the requirements for the mandatory operation region in Requirement R2.2.

2.3.1 If a facility enters current block mode, it shall restart current exchange in less than or equal to five cycles of positive sequence voltage returning to a continuous operation region or mandatory operation region.

2.4. Each facility shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable high voltage thresholds and time

[4] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for inverter-based resources. In case of offshore wind plants connecting via a dedicated VSC-HVDC, the main power transformer is the onshore main power transformer.

[5] Except if this would occur during a frequency excursion. The active power response should recover in accordance with the primary frequency controller.

[6] In either case and if required, the magnitude of active power and reactive current shall be as specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

durations in its response as voltage recovers from the mandatory or permissive operation regions to the continuous operation region.

2.5. Each facility shall restore active power output to the pre-disturbance or available level (whichever is lesser) within 1.0 second when the voltage at the high-side of the main power transformer returns from the mandatory operation region or permissive operation region (including operating in current block mode), as specified in Attachment 1, unless the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires a lower post-disturbance active power level requirement or requires a different post-disturbance active power restoration time.[7]

M2. Each Generator Owner and Transmission Owner have evidence of dynamic simulations, studies, or other evidence to demonstrate the design of each facility will adhere to requirements, as specified in Requirement R2. Each Generator Owner and Transmission Owner also have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrating that the operation of each facility did adhere to performance requirements, as specified in Requirement R2, during each voltage excursion measured at the high-side of the main power transformer. The Generator Owner or Transmission Owner have evidence of receiving such performance requirements, (e.g. email exchange, contract information) if the Transmission Planner, Transmission Operator, Reliability Coordinator, or Planning Coordinator has required the Generator Owner or Transmission Owner to follow performance requirements other than those in Requirement R2 (e.g. ramp rates, reactive power prioritization).

R3. Each Generator Owner or Transmission Owner shall ensure the design and operation is such that each facility adheres to Ride-through requirements during a frequency excursion event whereby the System frequency remains within the "must Ride-through zone" according to Attachment 2 and the absolute rate of change of frequency (RoCoF)[8] magnitude is less than or equal to 5 Hz/second. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

M3. Each Generator Owner and Transmission Owner have evidence of dynamic simulations, studies, or other evidence to demonstrate the design of each facility will adhere to Ride-through requirements, as specified in Requirement R3. Each Generator Owner and Transmission Owner also have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate the operation of each facility did adhere to Ride-through requirements, as specified in Requirement R3, during each frequency excursion event measured at the high-side of the main power transformer.

R4. Each Generator Owner and Transmission Owner identifying a facility that is in-service by the effective date of PRC-029-1, has known hardware limitations that prevent the

[7] Except if this would occur during a frequency excursion. The active power response should recover in accordance with the primary frequency controller.

[8] Rate of change of frequency (ROCOF) is calculated as the average rate of change for multiple calculated system frequencies for a time period of greater than or equal to 0.1 second. ROCOF is not calculated during the fault occurrence and clearance.

facility from meeting voltage Ride-through criteria as detailed in Requirements R1 and R2, and requires an exemption from specific voltage Ride-through criteria shall*:*[9] *Lower] [Time Horizon: Long-term Planning]*

4.1. Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1. This documentation shall include:

4.1.1 Identifying information of the IBR (name, facility #, other);

4.1.2 Which aspects of voltage ride-through requirements that the IBR would be unable to meet and the capability of the equipment due to the limitation;

4.1.3 Identify the specific piece(s) of equipment causing the limitation;

4.1.4 Supporting technical documentation verifying the limitation is due to hardware that needs to be physically replaced or that the limitation cannot be removed by software updates or setting changes, and;

4.1.5 Information regarding any plans to remedy the equipment limitation (such as an estimated date).

4.2. Provide a copy of the information detailed in Requirement R4.1 to the applicable Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and to the Regional Entity no later than 12 months following the effective date of PRC-029-1.

4.2.1 Any response to additional information requested by the applicable Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and to the Regional Entity shall be provided back to the requestor within 90 days of the request.

4.3. Each Generator Owner and Transmission Owner with a previously submitted request for exemption that replace the equipment causing the limitation shall document and communicate such an equipment change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the equipment change.

4.3.1 When existing equipment is replaced, the exemption for that Ride-through criteria no longer applies.

M4. Each Generator Owner and Transmission Owner seeking an exemption for facilities that are in-service by the effective date of PRC-029-1 have evidence of submission to the Regional Entity consistent with the information listed in Requirement R4.1. Each Generator Owner and Transmission Owner have evidence of communicated copies of each submission in accordance with Requirement R4.2 and to the applicable entities described in Requirement R4.2. Acceptable type of evidence for submittals include but

[9] The exemption requests for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction

are not limited to, meeting minutes, agreements, copies of procedures or protocols in effect, or email correspondence. Acceptable types of evidence for an equipment limitation may include but is not limited to, documentation that contains study results, experience from an actual event, or manufacturer's advice. Each Generator Owner and Transmission Owner that replace equipment at a facility that is directly associated with an approved exemption and that equipment is the cause for the limitation, have evidence of communicating the equipment change to the applicable entities described in Requirement R4.3 within 30 calendar days of the equipment replacement.

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.

1.2. Evidence Retention: 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.

- Each Generator Owner and Transmission Owner shall retain evidence with Requirements R1, R2, and R3 in this standard for 36 calendar months.
- Each Generator Owner and Transmission Owner shall retain evidence with Requirement R4 in this standard for five calendar years.

1.3. Compliance Monitoring and Enforcement 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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Owner or Transmission Owner failed to demonstrate the capability of each applicable facility to Ride-through in accordance with Attachment 1, except for those conditions identified in Requirement R1.	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable facility adhered to Ride-through requirements in accordance with Attachment 1, except for those conditions identified in Requirement R1.
R2.	The Generator Owner or Transmission Owner failed to demonstrate the capability of each applicable facility to adhere to performance requirements during voltage excursions, as specified in Requirement R2.	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable facility adhered to performance requirements during voltage excursions, as specified in Requirement R2.
R3.	The Generator Owner or Transmission Owner failed to demonstrate the capability of each applicable facility to Ride-through in accordance with Attachment 2.	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable facility adhered to Ride-through requirements in accordance with Attachment 2.
R4.	The Generator Owner or Transmission Owner with a previously communicated equipment limitation that	The Generator Owner or Transmission Owner with a previously communicated equipment limitation that	The Generator Owner or Transmission Owner with a previously communicated equipment limitation that	The Generator Owner or Transmission Owner failed to document complete information for facilities

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and Regional Entity more than 30 calendar days but less than or equal to 60 calendar days after the change to the equipment. OR The Generator Owner or Transmission Owner provided a copy to the applicable entities as detailed in R4.2 more than 12 months but less than or equal to 15 months after the effective date of R4.	repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and Regional Entity more than 60 calendar days but less than or equal to 90 calendar days after the change to the equipment.	repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and Regional Entity more than 90 calendar days but less than or equal to 120 calendar days after the change to the equipment.	identified with known hardware limitations that prevent the facility from meeting voltage Ride-through criteria as detailed in Requirements R1 or R2. OR The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s),Reliability Coordinator(s), and Regional Entity more than 120 calendar days after the change to the equipment. OR The Generator Owner or Transmission Owner failed to provide a copy to the applicable entities as detailed in R4.2 within 24 months after the effective date of R4.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan .

Version History

Version	Date	Action	Change Tracking
Initial Draft	3/27/24	DRAFT	
DRAFT 2	6/4/24	Revised follow initial comment review	

Attachment 1: Voltage Ride-Through Criteria

Table 1: Voltage Ride-Through Requirements for AC-Connected Wind Facility[10]

Voltage (per unit)[11]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[12]	N/A
≤ 1.20 and ≥ 1.1	Mandatory Operation Region	1.0
≤ 1.10 and > 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90 and ≥ 0.70	Mandatory Operation Region	3.00
< 0.70 and ≥ 0.50	Mandatory Operation Region	2.50
< 0.50 and ≥ 0.25	Mandatory Operation Region	1.20
< 0.25 and ≥ 0.10	Mandatory Operation Region	0.16
< 0.10	Permissive Operation Region	0.16

Table 2: Voltage Ride-Through Requirements for All Other Inverter-based Resource Facilities

Voltage (per unit)[13]	Operation Region	Minimum Ride-Through Time (sec)
>1.20	N/A[14]	N/A
≤ 1.20 and > 1.1	Mandatory Operation Region	1.0
≤ 1.10 and > 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90 and ≥ 0.70	Mandatory Operation Region	6.00
< 0.70 and ≥ 0.50	Mandatory Operation Region	3.00
< 0.50 and ≥ 0.25	Mandatory Operation Region	1.20
< 0.25 and ≥ 0.10	Mandatory Operation Region	0.32
< 0.10	Permissive Operation Region	0.32

[10] Type 3 and type 4 wind resources directly connected to the AC Transmission System
[11] Refer to bullet #5 below.
[12] These conditions are referred to as the "may Ride-through zone".
[13] Refer to bullet #5 below.
[14] These conditions are referred to as the "may Ride-through zone".

1. Table 1 applies to type 3 and type 4 wind facilities unless connected via a dedicated VSC-HVDC transmission facility.
2. Table 2 applies to all other inverter-based resource facility types not covered in Table 1; including, but not limited to, the following facilities:
   a. Inverter-based resources, regardless of their energy resource, interconnecting via a dedicated VSC-HVDC transmission facility.
   b. Other inverter-based resource plants or hybrid plants consisting of photovoltaic (PV) and BESS.
3. The applicable voltage for Voltage Source Converter High Voltage Direct Current (VSC HVDC) system with a dedicated connection to an inverter-based resource is on the AC side of the transformer(s) that is (are) used to connect the VSC HVDC system to the interconnected transmission system
4. Table 1 applies to hybrid facilities consisting of wind (type 3 or type 4) and various other IBR technologies. Otherwise, Table 2 applies to hybrid facilities with no wind (type 3 or type 4).
5. The voltage base for per unit calculation is the nominal phase-to-ground or phase-to-phase transmission system voltage unless otherwise defined by the Planning Coordinator or Transmission Planner.
6. The applicable voltage for Tables 1 and 2 is identified as the voltage max/min of phase to neutral or phase to phase fundamental root mean square (RMS) voltage at the high side of the main power transformer.
7. Tables 1 and 2 are only applicable when the frequency is within the “must Ride-through zone” as specified in Table 3 of Attachment 2.
8. At any given voltage value, each facility shall Ride-through unless the time duration at that voltage has exceeded the specified minimum Ride-through time duration. If the voltage is continuously varying over time, it is necessary to add the duration within each band of Tables 1 and 2 over any 10 second time period.
9. The specified duration of the mandatory operation regions and the permissive operation regions in Tables 1 and 2 is cumulative over one or more disturbances within any 10 second time period.
10. The facility may trip for more than four deviations of the applicable voltage at the high-side of the main power transformer outside of the continuous operation region within any 10 second time period.
11. Instantaneous trip settings based on instantaneously calculated voltage measurements with less than filtering lengths of one cycle (16.6 msec) are not permissible.
12. The “must Ride-through zone” is the combined area of the mandatory operating regions, the continuous operating regions, and the permissive operating region. All

area outside of these operating regions is referred to as the “may Ride-through zone”.

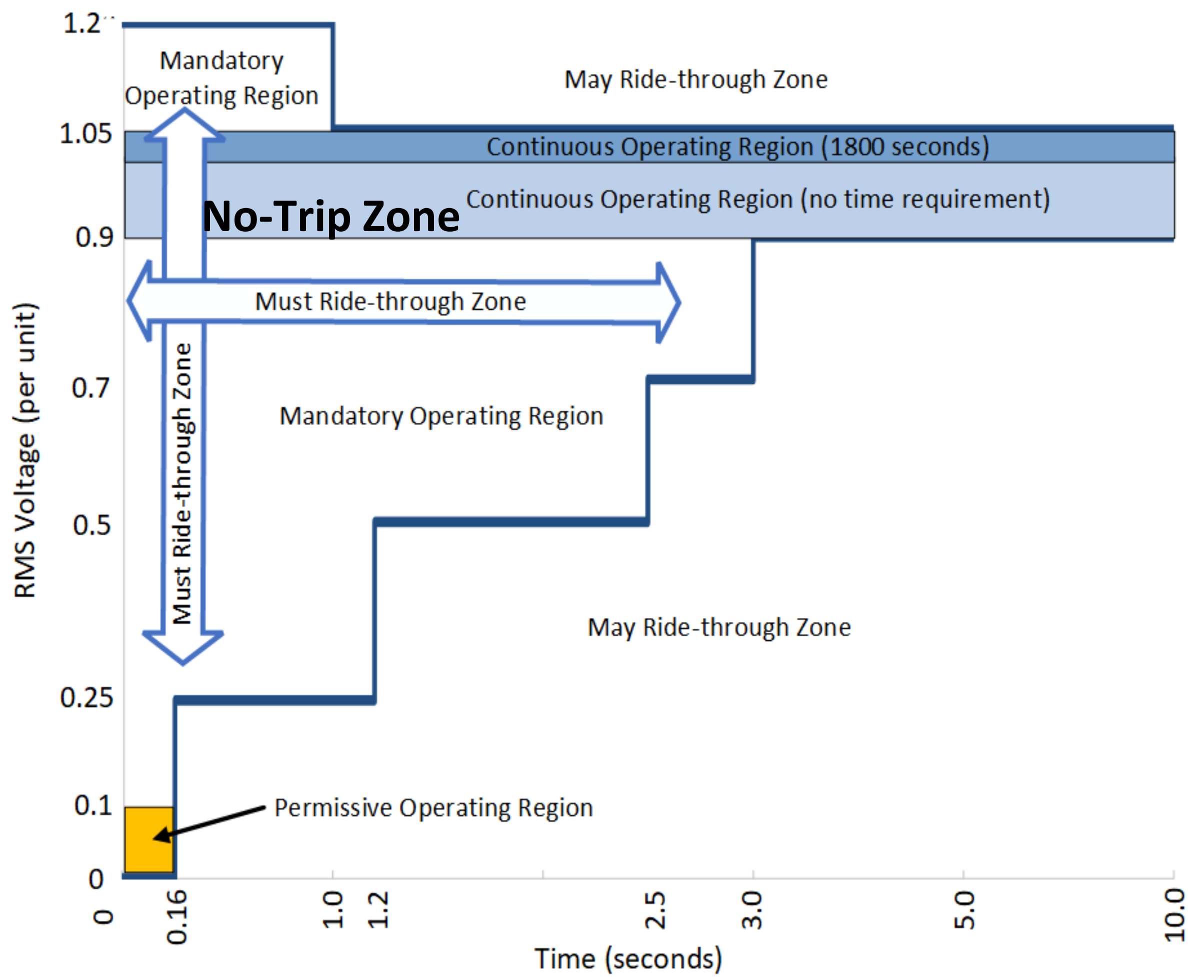


Figure 1: Voltage Ride-Through Requirements for AC-Connected Wind Facilities

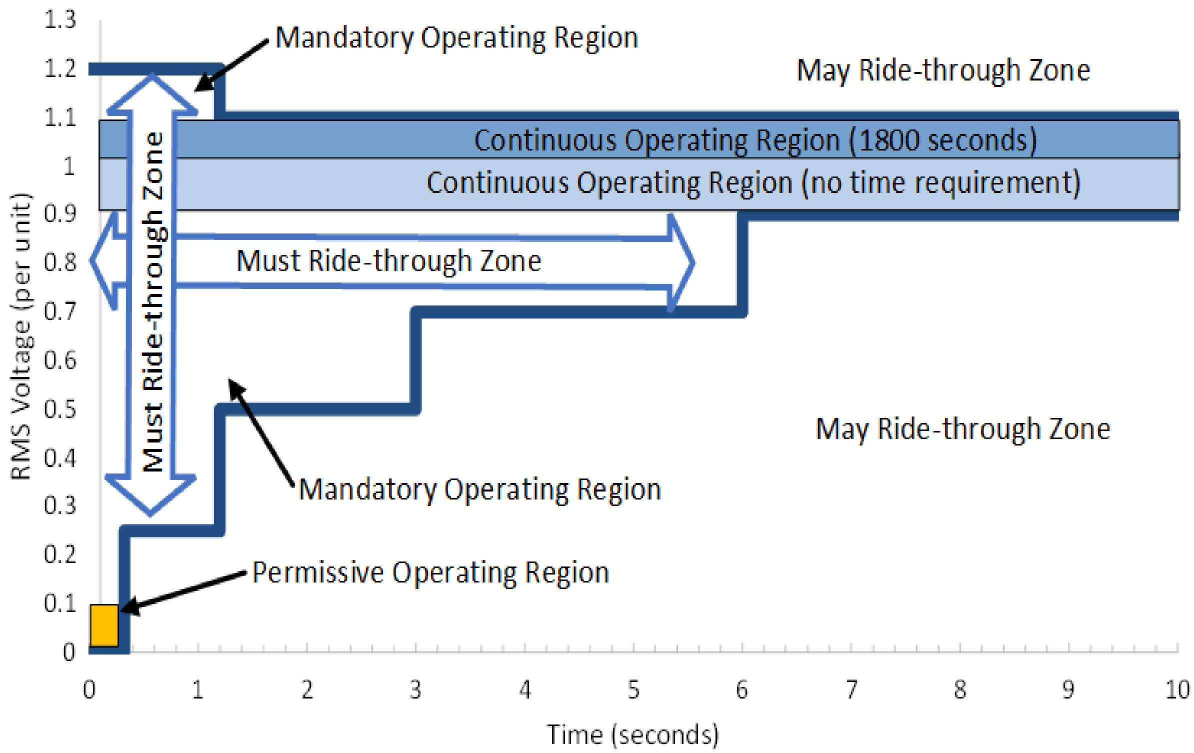


Figure 2: Voltage Ride-Through Requirements for All Other IBR

Attachment 2: Frequency Ride-Through Criteria

Table 3: Frequency Ride-Through Capability Requirements

System Frequency (Hz)	Minimum Ride-Through Time (sec)
≥64	May trip
< 64 and ≥61.8	6
< 61.8 and ≥ 61.5	299
< 61.5 and > 61.2	660
≤ 61.2 and < 58.8	Continuous
≤ 58.8 and < 58.8	660
< 58.5 and ≥ 57	299
< 57.0 and ≥ 56	6
< 56	May trip

1. Frequency measurements are taken at the high-side of the main power transformer.
2. Frequency is measured over a period of time (typically 3-6 cycles) to calculate system frequency at the high-side of the main power transformer.
3. Instantaneous or single points of measurement may not be used in the determination of control settings.
4. At any given frequency value, each facility shall Ride-through unless the time duration at that frequency has exceeded the specified minimum ride-through time duration.
5. The specified durations of Table 3 are cumulative over one or more disturbances within a 15-minute time period.

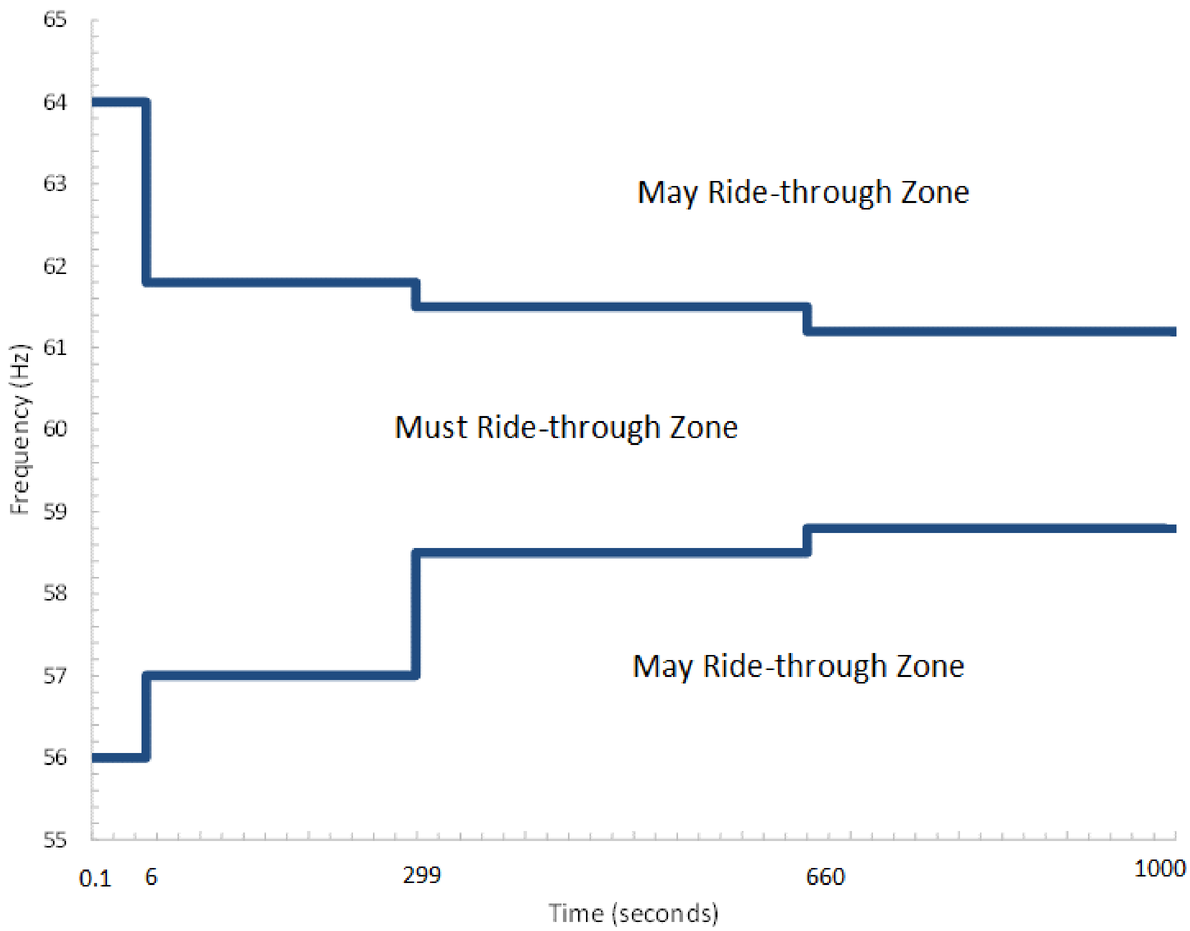


Figure 3: PRC-029 Frequency Ride-Through Requirements

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

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023

Anticipated Actions	Date
15-day formal comment period and additional ballot	June 18 – July 8, 2024
Final Ballot	July 16 - 20, 2024
Board adoption	August 14, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Ride-through: Remaining connected, synchronized with the Transmission System, and continuing to operate in response to System conditions through the time-frame of a System Disturbance.

~~**Continuous Operating Region** – The range of voltages, measured at the high-side of the main power transformer, that are ≥ 0.9 per unit and ≤ 1.1 per unit.~~

~~**Mandatory Operating Region** – The range of voltages, measured at the high-side of the main power transformer, that are > 0.1 per unit and < 0.9 per unit – or – > 1.1 and ≤ 1.2 per unit.~~

~~**Permissive Operating Region** – The range of voltages, measured at the high-side of the main power transformer, that is ≤ 0.1 per unit.~~

A. Introduction

1. **Title:** **Frequency and Voltage Ride-through Requirements for Inverter-Based ~~Generating~~ Resources**
2. **Number:** **PRC-029-1**
3. **Purpose:** To ensure that Inverter-Based Resources (IBRs) adhere to Ride-through requirements ~~remain connected and perform operationally~~ as expected to support ~~of~~ the Bulk Power System (BPS) during and after defined frequency and voltage excursions.
4. **Applicability:**

   4.1 Functional Entities:

   4.1.1. Generator Owner

   4.1.2. Transmission Owner[1]

   4.2 Facilities: ~~**For purposes of this standard, the term "applicable Inverter-Based Resource" or "applicable Inverter-Based Resources" refers to the following:**~~

   4.2.1. BE~~P~~S inverter-based resources[2] ~~IBRs~~

   4.2.2. IBR Registration Criteria

~~5.~~ **Effective Date:** See Implementation Plan for Project 2020-02 – PRC-029-1

Standard-Only Definition: None

[1] For owners of Voltage Source Converter – High-voltage Direct Current (VSC-HVDC) transmission facilities that are dedicated connections for IBR to the BPS

[2] For the purpose of this standard, "inverter-based resources" refers to a collection of individual solar photovoltaic (PV), Type 3 and Type 4 wind turbines, battery energy storage system (BESS), or fuel cells that operate as a single plant/resource. In case of offshore wind plants connecting via a dedicated VSC-HVDC, the inverter-based resource includes the VSC-HVDC system.

B. Requirements and Measures

R1. Each Generator Owner or Transmission Owner ~~of an applicable IBR~~ shall ensure the~~at~~ design and operation is such that each facility~~IBR~~ adheres to Ride-through requirements,~~remains electrically connected and continues to exchange current~~ in accordance with the “must Ride-through[3]~~no-trip~~ zone~~s~~” ~~and operation regions~~ as specified in Attachment 1, except for the following:~~unless needed to clear a fault or a documented equipment limitation exists in accordance with Requirement R6.~~ *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

- The facility needed to electrically disconnect in order to clear a fault;
- A documented equipment limitation exists in accordance with Requirement R4; or
- The instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer and is initiated by a non-fault switching event on the transmission system; or
- The Volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

M1. Each Generator Owner and Transmission Owner ~~shall~~ have evidence of dynamic simulations, studies, or other evidence to demonstrate the design of each facility will adhere to Ride-through requirements, as specified in Requirement R1. Each Generator Owner and Transmission Owner have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) ~~recorded~~ to demonstrate that the operation of each facility did adhere to Ride-through requirements, as specified in Requirement R1. If the Generator Owner and Transmission Owner choose to utilize Ride-through exemptions that occur within the “must Ride-through zone” and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner and Transmission Owner also have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate that the facility failed to Ride-through during a phase jump of greater than or equal to 25 electrical degrees, and documentation from their Transmission Planner, Reliability Coordinator, Planning Coordinator, or Transmission Operator that a non-fault initiated switching event occurred.~~data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in **Requirement R1**~~.

R2. Each Generator Owner or Transmission Owner ~~of an applicable IBR~~ shall ensure the design and operation is such that ~~at during a System disturbance, each IBR's~~ the voltage performance for each facility adheres to the following during a voltage excursion, unless a documented equipment limitation exists in accordance with Requirement R4~~6~~. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

[3] Includes no tripping associated with phase lock loop loss of synchronism

2.1. While the voltage at the high-side of the main power transformer[4] remains within the ~~C~~continuous ~~O~~operation ~~R~~region as specified in Attachment 1, each ~~IBR~~ facility shall:

2.1.1 Continue to deliver the pre-disturbance level of active power or available active power, whichever is less.[5] ~~,~~

~~**2.1.1**~~**2.1.2** ~~and c~~Continue to deliver reactive power ~~and reactive power~~ up to its ~~apparent~~ reactive power limit and according to its controller settings.

~~**2.1.2**~~**2.1.3** If the facility~~IBR~~ cannot deliver both active and reactive power due to a current ~~or apparent power~~ limit or reactive power limit, when the ~~applicable~~ voltage is below 95~~%~~ per unit and still within the ~~C~~continuous o~~O~~peration ~~R~~region, then preference shall be given to active or reactive power according to requirements if required ~~specified~~ by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.2. While voltage at the high-side of the main power transformer is within the ~~M~~mandatory o~~O~~peration ~~R~~region as specified in Attachment 1, each IBR shall exchange current, up to the maximum capability to provide voltage support, on the affected phases during both symmetrical and asymmetrical voltage disturbances, either under[6]:

~~**2.2.1**~~ • Reactive power priority by default; or~~Exchange current, up to the maximum capability while maintaining automatic voltage regulation, on the affected phases during both symmetrical and asymmetrical voltage disturbances.~~

~~**2.2.2**~~ • Active ~~djust reactive current injection at the high-side of the main~~ power priority ~~transformer so that the magnitude of the reactive current responds to changes in voltage at the high-side of the main power transformer in accordance with default reactive prioritization unless the~~ if required by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator. ~~specifies a certain magnitude of reactive power response to voltage changes or specifies active power priority instead of reactive power priority.~~

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[4] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for inverter-based resources. In case of offshore wind plants connecting via a dedicated VSC-HVDC, the main power transformer is the onshore main power transformer.

[5] Except if this would occur during a frequency excursion. The active power response should recover in accordance with the primary frequency controller.

[6] In either case and if required, the magnitude of active power and reactive current shall be as specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.3. While ~~The IBR shall not itself cause~~ voltage at the high-side of the main power transformer is within the permissive operation region~~to exceed the applicable~~, as specified in Attachment 1, each facility ~~Table 1 or Table~~ may operate in current block mode if necessary to avoid tripping. Otherwise, each facility shall follow the requirements for the ~~2 no-trip zone voltage thresholds and time durations in its response from M~~mandatory ~~or Permissive O~~operation ~~R~~region in Requirement R2.2~~s to the Continuous Operating Region~~.

~~2.3.~~2.3.1 If a facility enters current block mode, it shall restart current exchange in less than or equal to five cycles of positive sequence voltage returning to a continuous operation region or mandatory operation region.

2.4. Each ~~IBR~~ facility shall not itself cause ~~restore active power output to the pre-disturbance or available level within 1.0 second when the~~ voltage at the high-side of the main power transformer ~~returns~~ to exceed the applicable high voltage thresholds and time durations in its response as voltage recovers from the mandatory or permissive operation regions to the ~~C~~continuous ~~O~~operation ~~R~~region ~~from the Mandatory Operation Region or Permissive Operation Region (including operation in current block mode) as specified in **Attachment 1**, unless the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specifies a lower post-disturbance active power level requirement or specifies a different post-disturbance active power restoration time~~.

2.5. Each ~~IBR~~ facility shall restore active power output to the pre-disturbance or available level (whichever is lesser) within 1.0 second~~only trip to prevent equipment damage,~~ when the voltage at the high-side of the main power transformer returns from the mandatory operation region or permissive operation region (including operating in current block mode), ~~is outside of the no-trip zone~~ as specified in Attachment 1, unless the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires a lower post-disturbance active power level requirement or requires a different post-disturbance active power restoration time.[7]

M2. Each Generator Owner and Transmission Owner ~~shall~~ have evidence of dynamic simulations, studies, or other evidence to demonstrate the design of each facility will adhere to requirements, as specified in Requirement R2. Each Generator Owner and Transmission Owner also have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder)~~recorded~~ data ~~or other evidence for each applicable IBR~~to ~~demonstrating~~demonstrating that the operation of each facility did adhere~~nce~~ to performance requirements, as specified in Requirement R2, during each ~~System~~ voltage excursion measured at the high-side of the main power transformer. The Generator Owner or Transmission Owner have evidence of receiving such

[7] Except if this would occur during a frequency excursion. The active power response should recover in accordance with the primary frequency controller.

performance requirements, (e.g. email exchange, contract information) if the Transmission Planner, Transmission Operator, Reliability Coordinator, or ~~disturbance which has occurred within the associated~~ Planning Coordinator~~(s) area(s)~~ has required the Generator Owner or Transmission Owner to follow performance requirements other than those in Requirement R2 (e.g. ramp rates, reactive power prioritization).

~~**R3.** Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that during a transient overvoltage as a result of a switching event whereby instantaneous voltage at the high-side of the main power transformer exceeds 1.2 per unit, each IBR shall either: *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*~~

- ~~Remain electrically connected and continue to exchange current in accordance with instantaneous transient overvoltage levels and durations specified in Attachment 2; or~~
- ~~Remain electrically connected in current block mode in accordance with instantaneous transient overvoltage levels and durations specified in **Attachment 2**, and restart current exchange within 5 cycles of the instantaneous voltage falling below (and remaining below) 1.2 per unit.~~

~~**M3.** Each Generator Owner and Transmission Owner shall have evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to performance requirements, as specified in Requirement R3, during each transient overvoltage period which has occurred within the associated Planning Coordinator(s) area(s).~~

~~R4.~~R3. Each Generator Owner or Transmission Owner ~~of an applicable IBR~~ shall ensure the design and operation is such that each ~~IBR~~ facility~~remains electrically connected and continues to exchange current~~ adheres to Ride-through requirements during a frequency excursion event whereby the System frequency remains within the "~~no trip~~must Ride-through zone" according to Attachment 2~~3~~ and the absolute rate of change of frequency (R~~O~~oC~~O~~oF)[8] magnitude is less than or equal to 5 Hz/second. *[Violation Risk Factor: ~~Lower~~High] [Time Horizon: Operations Assessment]*

M~~4~~3. Each Generator Owner and Transmission Owner ~~shall~~ have evidence of dynamic simulations, studies, or other evidence to demonstrate the design of each facility will adhere to Ride-through requirements, as specified in Requirement R3. Each Generator Owner and Transmission Owner also have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) ~~recorded~~ data ~~or other evidence~~ to demonstrate the operation of~~for~~ each ~~applicable IBR~~facility did ~~demonstrating~~ adheren~~ce~~ to ~~r~~Ride-through requirements, as specified in Requirement R~~4~~3, during each frequency excursion event measured ~~which has occurred within the associated Planning Coordinator(s) area(s)~~ at the high-side of the main power transformer.

[8] Rate of change of frequency (ROCOF) is calculated as the average rate of change for multiple calculated system frequencies for a time period of greater than or equal to 0.1 second. ROCOF is not calculated during the fault occurrence and clearance.

~~**R5.** Each Generator Owner or Transmission Owner of an applicable IBR shall ensure each IBR remains electrically connected and continues to exchange current during instantaneous positive sequence voltage phase angle changes that are initiated by non-fault switching events on the transmission system and are changes of less than 25 electrical degrees at the high-side of the main power transformer. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*~~

~~**5.1.** When the instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer and is initiated by a non-fault switching event on the transmission system, the IBR may trip, but shall only trip to prevent equipment damage.~~

~~**M5.** Each Generator Owner and Transmission Owner shall have evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in Requirement R5, during instantaneous positive sequence voltage phase angle changes that are changes of less than 25 electrical degrees at the high-side of the main power transformer and that such changes are not initiated by non-fault switching events.~~

~~R6.~~R4. Each Generator Owner and Transmission Owner identifying a facility that is in-service by the effective date of PRC-029-1, has known hardware~~with a documented equipment~~ limitations that ~~would~~ prevent the facility~~an applicable IBR that is in-service by the effective date of this standard~~ from meeting voltage ~~r~~Ride-through ~~requirements~~ criteria as detailed in Requirements R1 and R2, and requires an exemption from specific voltage Ride-through criteria shall~~communicate each equipment limitation to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s). *[Violation Risk Factor*~~*:*[9] *Lower] [Time Horizon: Long-term Planning]*

~~6.1.~~4.1. ~~Each Generator Owner and Transmission Owner shall include in its d~~Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1. This documentation shall include~~ation~~:

~~6.1.1~~4.1.1 Identifying information of the IBR (name, facility #, other);

~~6.1.2~~4.1.2 Which aspects of voltage ride-through requirements that the IBR would be unable to meet and the capability of the equipment due to the limitation;

~~6.1.3~~4.1.3 Identify the specific piece(s) of equipment causing the limitation;

4.1.4 Supporting technical documentation verifying the limitation is due to hardware that needs to be physically replaced or that the limitation cannot be removed by software updates or setting changes, and;

[9] The exemption requests for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction

~~6.1.4~~4.1.5 Information regarding any plans to ~~repair or~~ remedy~~place~~ the ~~limiting~~ equipment ~~that would remove the~~ limitation (such as an estimated date ~~of repair/replacement~~).

4.2. Provide a copy of the information detailed in Requirement R4.1 to the applicable Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and to the Regional Entity no later than 12 months following the effective date of PRC-029-1.

4.2.1 Any response to additional information requested by the applicable Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and to the Regional Entity shall be provided back to the requestor within 90 days of the request.

4.3. Each Generator Owner and Transmission Owner with a previously ~~communicated~~ submitted request for exemption~~equipment limitation~~ that ~~repairs or~~ replace~~s~~ the equipment causing the limitation shall document and communicate such an equipment change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within ~~3~~90 days of the equipment change.

~~6.2.~~4.3.1 When existing equipment is replaced, the exemption for that Ride-through criteria no longer applies.

M~~6~~4. Each Generator Owner and Transmission Owner seeking an exemption for facilities that are in-service by the effective date of PRC-029-1 ~~shall~~ have evidence of submission to the Regional Entity consistent with the information listed ~~equipment limitations, as specified~~ in Requirement R~~6~~4.1~~, documented prior to the effective date of PRC-029-1~~. Each Generator Owner and Transmission Owner have evidence of communicated copies of each submission in accordance with Requirement R4.2 and to the applicable entities described in Requirement R4.2. Acceptable type of evidence for submittals include but are not limited to, meeting minutes, agreements, copies of procedures or protocols in effect, or email correspondence. Acceptable types of evidence for an equipment limitation may include but is not limited to, documentation that contains study results, experience from an actual event, or manufacturer's advice. Each Generator Owner and Transmission Owner that replace ~~with changes to~~ equipment at a facility that is directly associated with an approved exemption and that equipment is the cause for the limitation, ~~shall~~ have evidence of communicating the equipment change to the applicable entities described in Requirement R4.3 within 30 calendar days of the equipment replacement~~communication to each associated Planning Coordinator, Transmission Planner, and Reliability Coordinator. Acceptable types of evidence may include, but are not limited to, meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence~~.

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.

   1.2. **Evidence Retention:** 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.

   - Each Generator Owner and Transmission Owner shall retain evidence with Requirements R1, R2, and R3 in this standard for 36 calendar months.
   - Each Generator Owner and Transmission Owner shall retain evidence with Requirement R4 ~~each requirement~~ in this standard for five calendar years.

   1.3. **Compliance Monitoring and Enforcement 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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Owner or Transmission Owner failed to demonstrate the capability of each applicable facility to Ride-through in accordance with Attachment 1, except for those conditions identified in Requirement R1.~~N/A~~	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable facility adhered to Ride-through requirements in accordance with Attachment 1, except for those conditions identified in ~~IBR remains electrically connected and continued to exchange current in accordance with Attachment 1, unless needed to clear a fault, in accordance with~~ Requirement R1.
R2.	The Generator Owner or Transmission Owner failed to demonstrate the capability of each applicable facility to adhere to performance requirements during voltage excursions, as specified in Requirement R2.~~N/A~~	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable facility adhered to performance requirements during voltage excursions~~IBR adhered to performance requirements during each System disturbance~~, as specified in Requirement R2.
~~R3.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Generator Owner or Transmission Owner failed to demonstrate each applicable~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~IBR adhered to performance requirements during each transient overvoltage period as specified in Requirement R3.~~
R~~3~~4.	The Generator Owner or Transmission Owner failed to demonstrate the capability of each applicable facility to Ride-through in accordance with Attachment 2.~~N/A~~	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable facility adhered to Ride-through requirements in accordance with Attachment 2.~~IBR adhered to performance requirements during each frequency excursion event, as specified in Requirement R4.~~
~~R5.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Generator Owner or Transmission Owner failed to demonstrate each applicable IBR adhered to performance requirements during each instantaneous positive sequence voltage phase angle change of less than 25 electrical degrees, as specified in Requirement R5.~~
R4~~6~~.	The Generator Owner or Transmission Owner with a previously communicated	The Generator Owner or Transmission Owner with a previously communicated	The Generator Owner or Transmission Owner with a previously communicated	The Generator Owner or Transmission Owner failed to document complete

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), ~~and~~ Reliability Coordinator(s), and Regional Entity more than 30 calendar days but less than or equal to 60 calendar days after the change to the equipment. OR The Generator Owner or Transmission Owner provided a copy to the applicable entities as detailed in R4.2 more than 12 months but less than or equal to 15 months after the effective date of R4.	equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), ~~and~~ Reliability Coordinator(s), Transmission Operator(s), and Regional Entity more than 60 calendar days but less than or equal to 90 calendar days after the change to the equipment.	equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), ~~and~~ Reliability Coordinator(s), Transmission Operator(s), and Regional Entity more than 90 calendar days but less than or equal to 120 calendar days after the change to the equipment.	information for facilities identified with known hardware~~evidence of equipment~~ limitations that prevent the facility from meeting voltage Ride-through criteria as detailed in Requirements R1 or R2~~consistent with Requirement R6 and prior to the effective date of PRC-029-1 Requirement R6~~. OR The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), ~~and~~ Reliability Coordinator(s), and Regional Entity more than 120 calendar

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				days after the change to the equipment. OR The Generator Owner or Transmission Owner failed to provide a copy to the applicable entities as detailed in R4.2 within 24 months after the effective date of R4.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan .

Version History

Version	Date	Action	Change Tracking
Initial Draft	3/27/24	DRAFT	
DRAFT 2	6/4/24	Revised follow initial comment review	

Attachment 1: Voltage Ride-Through Criteria

Table 1: Voltage Ride-Through Requirements for AC-Connected Wind ~~IBR~~ Facility[10]

Voltage (per unit)[11]	Operation Region	Minimum Ride-Through Time (sec)
>~~≥~~ 1.20~~0~~	N/A[12]	N/A
≤ 1.20 and ≥ 1.1	Mandatory Operation Region	1.0
≤ 1.10 and >~~≥~~ 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90 and ≥ 0.70	Mandatory Operation Region	3.00
< 0.70 and ≥ 0.50	Mandatory Operation Region	2.50
< 0.50 and ≥ 0.25	Mandatory Operation Region	1.20
< 0.25 and ≥ 0.10	Mandatory Operation Region	0.16
< 0.10	Permissive Operation Region	0.16

Table 2: Voltage Ride-Through Requirements for All Other ~~IBR~~Inverter-based Resource Facilities

Voltage (per unit)[13]	Operation Region	Minimum Ride-Through Time (sec)
>~~≥~~1.20~~0~~	N/A[14]	N/A
≤ 1.20 and > ~~≥~~1.1	Mandatory Operation Region	1.0
≤ 1.10 and > ~~≥~~1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90 and ≥ 0.70	Mandatory Operation Region	6.00
< 0.70 and ≥ 0.50	Mandatory Operation Region	3.00
< 0.50 and ≥ 0.25	Mandatory Operation Region	1.20
< 0.25 and ≥ 0.10	Mandatory Operation Region	0.32
< 0.10	Permissive Operation Region	0.32

[10] Type 3 and type 4 wind resources directly connected to the AC Transmission System

[11] Refer to bullet #5 below.

[12] These conditions are referred to as the “may Ride-through zone”.

[13] Refer to bullet #5 below.

[14] These conditions are referred to as the “may Ride-through zone”.

1. Table 1 applies to type 3 and type 4 wind facilities ~~applicable wind IBR~~ unless connected via a dedicated VSC-HVDC transmission facility.
2. Table 2 applies to all other inverter-based resource facility ~~IBR~~ types not covered in Table 1; including, but not limited to, the following ~~IBR~~facilities:
   a. ~~Isolated~~ Inverter-based resources~~IBR~~, regardless of their energy resource, interconnecting via a dedicated VSC-HVDC transmission facility.
   b. Other ~~IBR~~ inverter-based resource plants or hybrid plants consisting of photovoltaic (PV) and BESS.
3. The applicable voltage for Voltage Source Converter High Voltage Direct Current (VSC HVDC) system with a dedicated connection to an inverter-based resource is on the AC side of the transformer(s) that is (are) used to connect the VSC HVDC system to the interconnected transmission system

~~3.~~4. Table 1 applies to hybrid facilities consisting of wind (type 3 or type 4) ~~In the case of hybrid IBR consisting of wind~~ and various other IBR technologies~~, the applicable table shall be based on direction by the Transmission Planner~~. Otherwise, Table 2 applies to hybrid facilities with no wind (type 3 or type 4).

~~4.~~5. The voltage base for per unit calculation is the nominal phase-to-ground or phase-to-phase transmission system voltage unless otherwise defined by the Planning Coordinator or Transmission Planner.

~~5.~~6. The applicable voltage for Tables 1 and 2 is identified as the voltage max/min of phase to neutral or phase to phase fundamental root mean square (RMS) voltage at the high side of the ~~MPT~~main power transformer.

~~6.~~7. Tables 1 and 2 are only applicable when the frequency is within the "must Ride-through~~no trip~~ zone" as specified in Table 3 of Attachment ~~3~~2.

~~7.~~8. At any given voltage value, each ~~IBR~~ facility shall Ride-through ~~not trip until~~ unless the time duration at that voltage has exceed~~s~~ed the specified minimum R~~r~~ide-through time duration. If the voltage is continuously varying over time, it is necessary to add the duration within each band of Tables 1 and 2 over ~~the~~ any 10~~-~~second time period ~~to determine compliance~~.

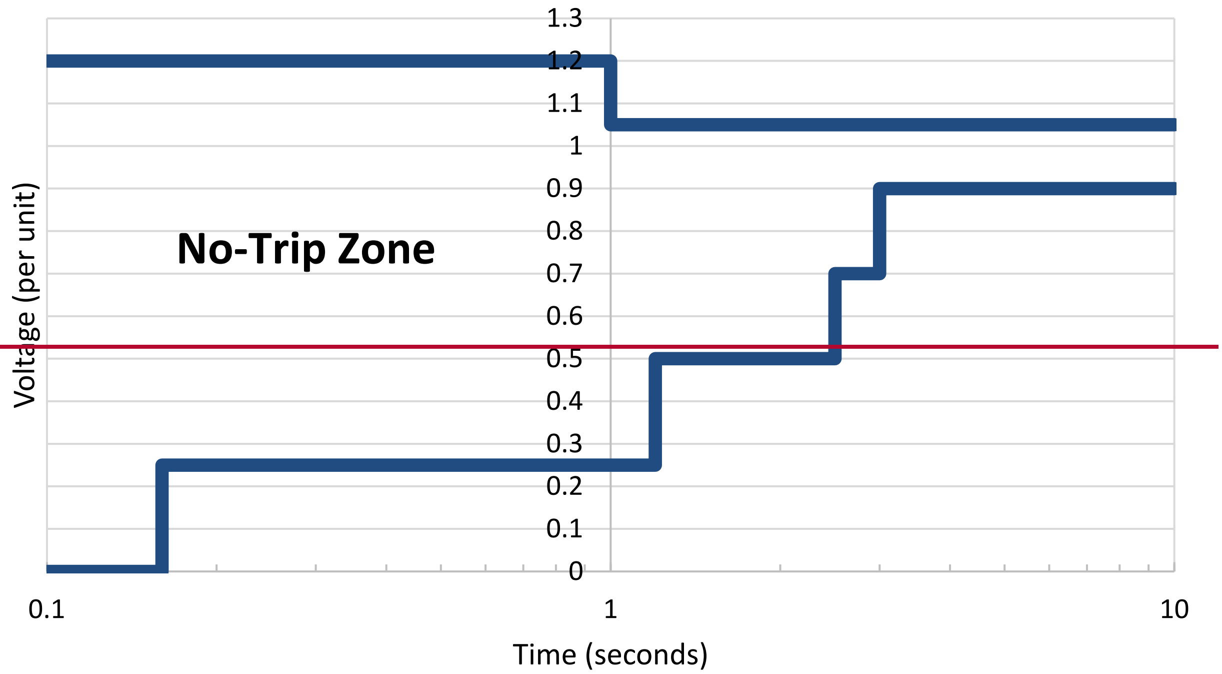
~~8.~~9. The specified duration of the ~~M~~mandatory ~~O~~operation ~~R~~regions and the ~~P~~permissive ~~O~~operation ~~R~~regions in Tables 1 and 2 is cumulative over one or more disturbances within any 10 second time period.

~~9.~~10. The ~~IBR~~ facility may trip for more than four deviations of the applicable voltage at the high-side of the main power transformer outside of the ~~C~~continuous ~~O~~operation ~~R~~region within any 10 second time period.

11. Instantaneous trip settings based on instantaneously calculated voltage measurements with less than filtering lengths of one cycle (16.6 msec) are not permissible.

12. The “must Ride-through zone” is the combined area of the mandatory operating regions, the continuous operating regions, and the permissive operating region. All area outside of these operating regions is referred to as the “may Ride-through zone”.

~~10. If the positive sequence voltage at the high-side of the main power transformer enters the Permissive Operation Region, an IBR may operate in current block mode if necessary to protect the equipment.~~


No-Trip Zone
Voltage (per unit)
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0.1
1
10
Time (seconds)

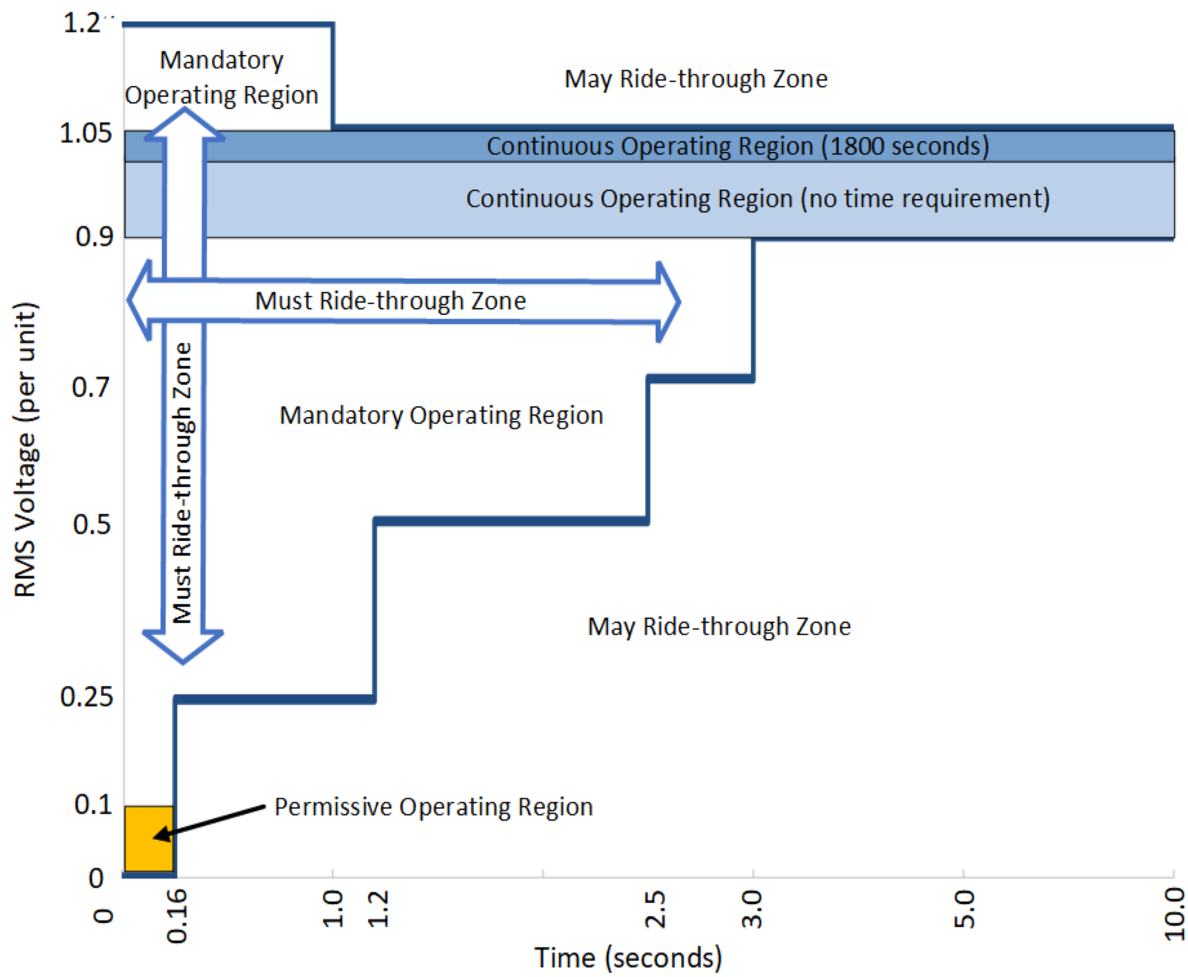


Figure 1: Voltage Ride-Through Requirements for AC-Connected Wind Facilities~~IBR~~

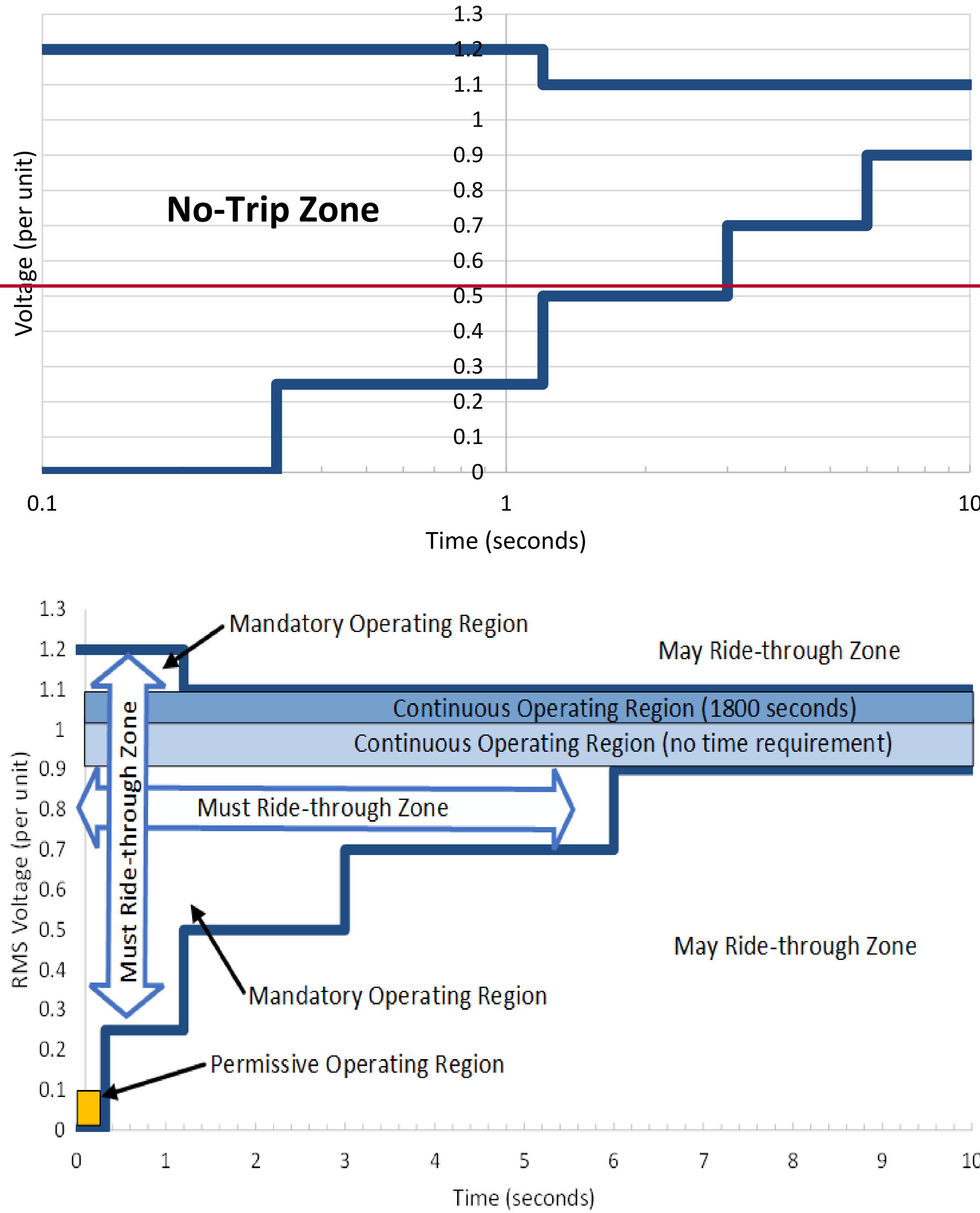


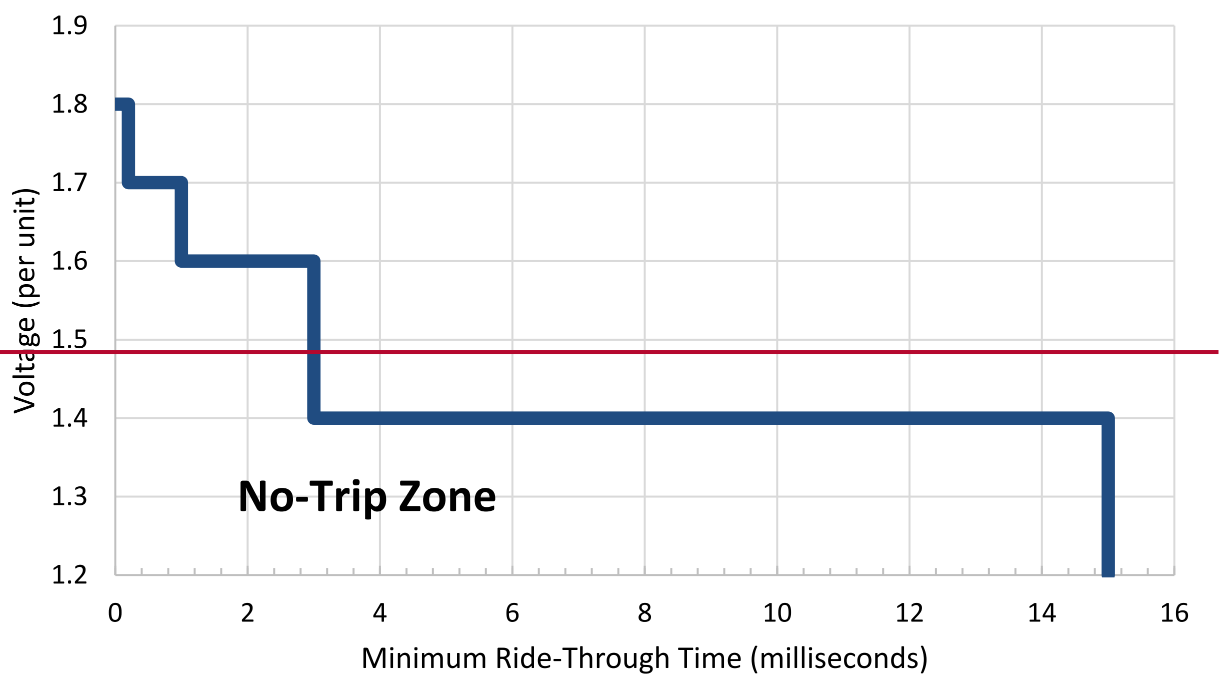
Figure 2: Voltage Ride-Through Requirements for All Other IBR

~~Attachment 2: Transient Overvoltage Ride-Through Criteria~~

~~Table 3: Transient Overvoltage Ride-Through Criteria~~

~~Voltage (per unit) at the high side of the MPT~~	~~Minimum Ride-Through Time (millisec)~~
~~> 1.8~~	~~May trip~~
~~> 1.7~~	~~0.2~~
~~> 1.6~~	~~1.0~~
~~> 1.4~~	~~3.0~~
~~> 1.2~~	~~15.0~~

1. ~~The voltage base for per unit calculation is the nominal instantaneous phase-to-ground or phase-to-phase voltage at the high side of the MPT unless otherwise defined by the Planning Coordinator or Transmission Planner.~~
1. ~~If surge protection devices are installed within the plant, the per unit voltage refers to the residual voltage with the surge arresters applied.~~
2. ~~Each IBR shall not trip unless the cumulative time of one or more instances over a 1-minute time window in which the instantaneous voltage exceeds the respective voltage threshold and the minimum ride-through time.~~



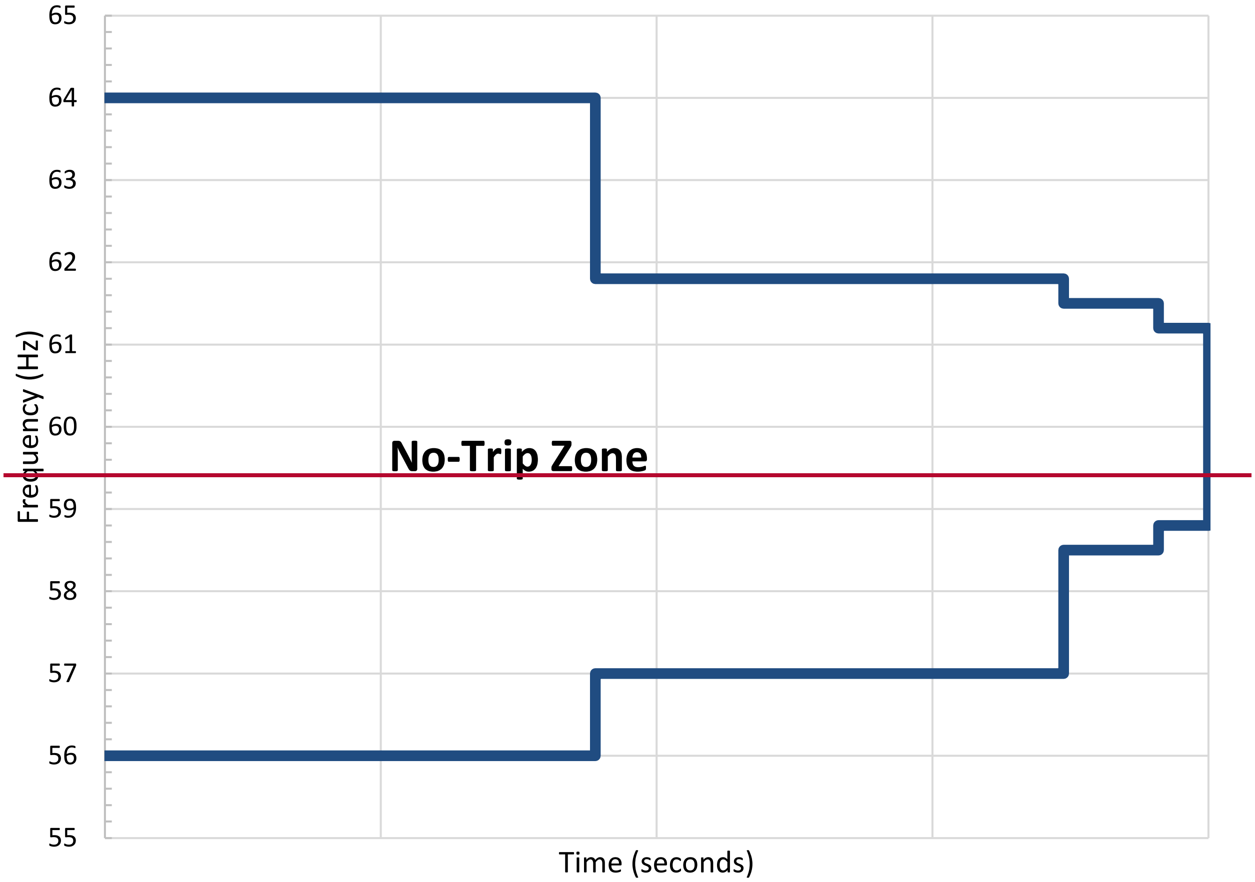
~~Figure 3: Transient Overvoltage Ride-Through Criteria~~

Attachment 2~~3~~: Frequency Ride-Through Criteria

Table 3~~3~~: Frequency Ride-Through Capability Requirements

~~Averaged~~ System Frequency (Hz)	Minimum Ride-Through Time (sec)
≥64	May trip
< 64 and ≥61.8	6
< 61.8 and ≥~~>~~ 61.5	299
< 61.5 and > 61.2	660
≤ 61.2 and < 58.8	Continuous
≤ 58.8 and < 58.8	660
< 58.5 and ≥ 57	299
< 57.0 and ≥ 56	6
< 56	May trip

1. Frequency ~~M~~measurements are taken at the high-side of the main power transformer ~~for each phase (phase to neutral)~~.
2. Frequency is ~~M~~measured~~ments are averaged~~ over a ~~set time~~ period of time (typically~~such as~~ 3-6 cycles) to calculate ~~averaged~~ system frequency at the high-side of the main power transformer.
3. Instantaneous or single points of measurement may not be used in the determination of control settings.
4. At any given frequency value~~s~~, each ~~IBR~~ facility shall Ride-through~~not trip until~~ unless the time duration at that frequency has exceeded~~s~~ the specified minimum ride-through time duration.
5. The specified durations of Table 3~~4~~ are cumulative over one or more disturbances within a 15-minute time period.


65
64
63
62
61
60
59
58
57
56
55
Frequency (Hz)
No-Trip Zone
Time (seconds)

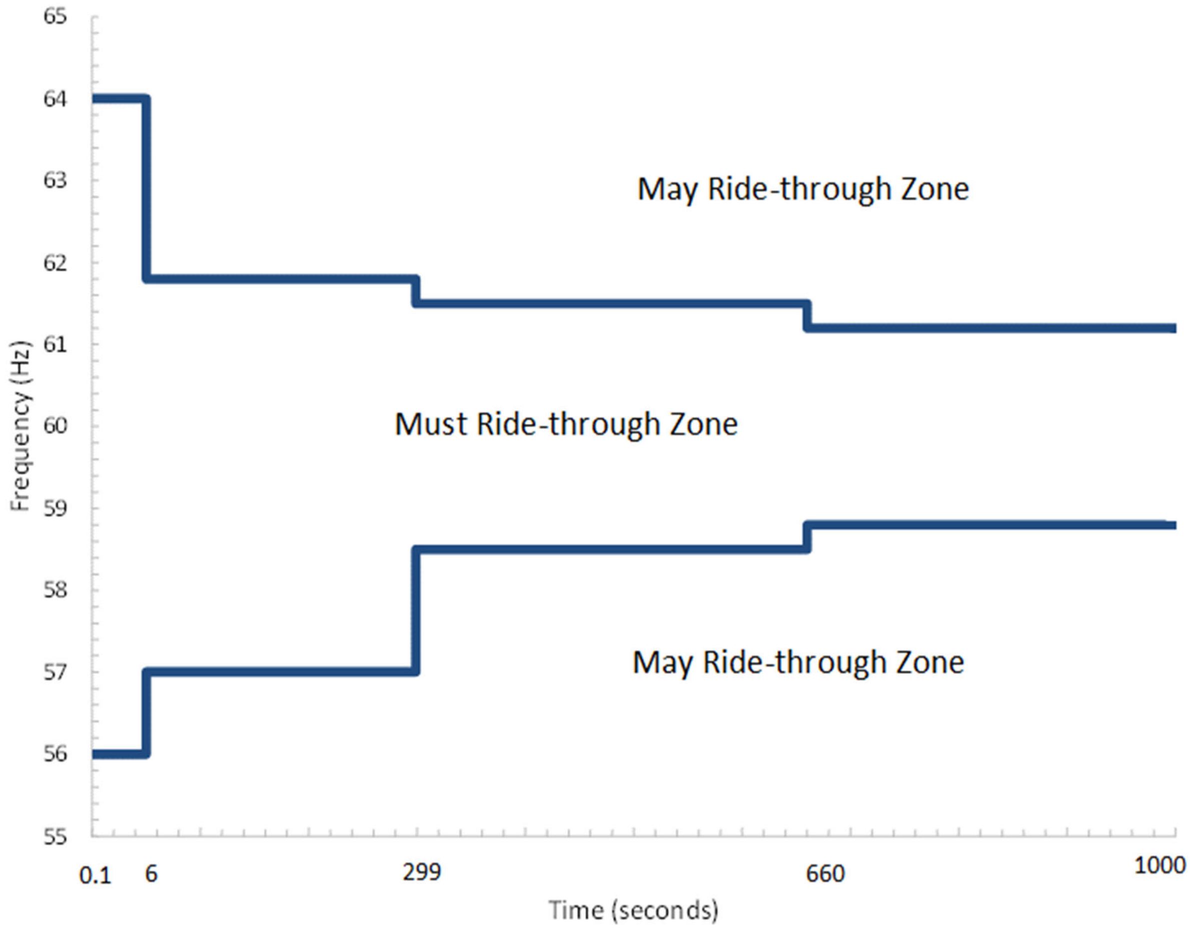


Figure ~~4~~3: PRC-029 Frequency ~~Envelopes~~Ride-Through Requirements

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Implementation Plan

Project 2020-02 Modifications to PRC-024 (Generator Ride-through) Reliability Standards PRC-024-4 and PRC-029-1

Applicable Standard(s)

- PRC-024-4 Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and Type 2 Wind Resources, and Synchronous Condensers
- PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Generating Resources

Requested Retirement(s)

- PRC-024-3 Frequency and Voltage Protection Settings for Generating Resources

Prerequisite Standard(s)

- PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

Proposed Definition(s)

- None

Applicable Entities

- See subject Reliability Standards.

Background

The purpose of Project 2020-02 is to modify Reliability Standard PRC-024-3 or replace it with a performance-based ride-through standard that ensures generators remain connected to the Bulk-Power System (BPS) during system disturbances. Specifically, the project focuses on using disturbance monitoring data to substantiate inverter-based resource (IBR) ride-through performance during grid disturbances. The project also ensures associated generators that fail to ride-through system events are addressed with a corrective action plan (if possible) and reported to necessary entities for situational awareness.

The purpose for this project is based on the culmination of multiple analyses conducted by the ERO Enterprise regarding widespread inverter-based resource tripping events. Furthermore, the NERC Inverter-Based Resource Performance Subcommittee[1] has developed comprehensive recommendations

[1] See documents at the NERC IRPS website: https://www.nerc.com/comm/RSTC/Pages/IRPS.aspx and the previous Inverter-Based Resource Performance Working Group website https://www.nerc.com/comm/RSTC/Pages/IRPWG.aspx

for improved performance of inverter-based resources, including the recommendation to develop comprehensive ride-through requirements.

In October 2023, FERC issued Order No. 901[2] which directs the development of new or modified Reliability Standards that include new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. In January 2024, NERC submitted a filing to FERC outlining a comprehensive work plan to address the directives within Order No. 901.[3] Within the work plan, NERC identified three active Standards Development projects that would need to be filed for regulatory approval with FERC by November 4, 2024. These projects include **2020-02 Modifications to PRC-024 (Generator Ride-through)**[4], **2021-04 Modifications to PRC-002-2**[5], and **2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues**[6].

Project 2020-02

Proposed Reliability Standard PRC-029-1 is a new Reliability Standard that includes ride-through requirements and performance requirements for IBRs. The scope of this project was adjusted to align with associated regulatory directives from FERC Order No. 901 and the scope of the other projects related to "Milestone 2" of the NERC work plan. The components of this project's Standard Authorization Request (SAR) that related to the inclusions of new data recording requirements are covered in Project 2021-04 and the proposed new PRC-028-1 Reliability Standard. Components of this project's SAR that relate to analytics and corrective actions plans are covered in Project 2023-02 and the proposed new PRC-030-1 Reliability Standard.

PRC-029-1 includes requirements for Generator Owner and Transmission Owner IBR to continue to inject current and perform frequency support during a BPS disturbance. The standard also specifically requires Generator Owner and Transmission Owner IBR to prohibit momentary cessation in the no-trip zone during disturbances.

PRC-024-4 includes modifications to revise applicable facility types to remove IBR and to include synchronous condensers.

[2] See FERC Order 901, Docket No. RM22-12-000; https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false; October 19, 2023

[3] See INFORMATIONAL FILING OF THE NORTH AMERICAN RELIABILITY CORPORATION REGARDING THE DEVELOPMENT OF RELIABILITY STANDARDS RESPONSIVE TO ORDER NO. 901 https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/NERC%20Compliance%20Filing%20Order%20No%20901%20Work%20Plan_packaged%20-%20public%20label.pdf; January 17, 2024

[4] See NERC Standards Development Project page for Project 2002-02; https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx

[5] See NERC Standards Development Project page for Project 2021-04; https://www.nerc.com/pa/Stand/Pages/Project-2021-04-Modifications-to-PRC-002-2.aspx

[6] See NERC Standards Development Project page for Project 2023-02; https://www.nerc.com/pa/Stand/Pages/Project-2023-02-Performance-of-IBRs.aspx

General Considerations

The ERO Enterprise acknowledges that there are IBRs currently in operation and unable to meet voltage ride-through requirements due to their inability to modify their coordinated protection and control settings. Consistent with FERC Order No. 901, a limited and documented exemption process for those IBR is appropriate and included within this Implementation Plan. Other NERC Standards Development projects will be pursued to address ongoing identification and mitigation of any potential reliability impacts to the BPS for such exemptions.

Effective Date and Phased-in Compliance Dates

The effective dates for the proposed Reliability Standards are provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance dates for those particular sections represent the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

PRC-024-4

Where approval by an applicable governmental authority is required, Reliability Standard PRC-024-4 shall become effective on the first day of the first calendar quarter that is 6 months after the effective date of the applicable governmental authority's order approving the PRC-028-1 standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the Reliability Standard PRC-024-4 shall become effective on the first day of the first calendar quarter that is 6 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

PRC-029-1

Where approval by an applicable governmental authority is required, Reliability Standard PRC-029-1 shall become effective on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the PRC-028-1 standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the Reliability Standard PRC-029-1 shall become effective on the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

PRC-024-3

Reliability Standard PRC-024-3 shall be retired immediately prior to the effective date of Reliability Standards PRC-024-04 and PRC-029-1 in the particular jurisdiction in which the revised standard is becoming effective.

Equipment Limitations and Process for Requirement R4

Consistent with FERC Order No. 901, a limited and documented exemption for some legacy IBR with certain documented equipment limitations are acceptable. Per the Order, these IBRs are

> "…typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements."[7]

To ensure compliance with Requirement R4 and alignment with FERC Order No. 901, only those IBR that are in operation as of the effective date of PRC-029-1 may be considered for potential exemption. Further, only those IBR that are unable to meet voltage ride-through requirements due to their inability to modify their coordinated protection and control settings may be considered for potential exemption.

[7] Order No. 901 at p. 193.

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Unofficial Comment Form

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2020-02 Modifications to PRC-024 (Generator Ride-through)** by **8 p.m. Eastern, Monday, July 8, 2024.**

Additional information is available on the project page. If you have questions, contact Manager of Standards Development, Jamie Calderon (email), or at 404-960-0568.

Background Information

The goal of Project 2020-02 is to mitigate the recent and ongoing disturbance ride through performance issues identified across multiple Interconnections and numbers of disturbances analyzed by NERC and the Regions. These issues have been associated with Inverter-Based Resources (IBR) with many causes of their tripping or cessation unrelated to voltage and frequency protection settings requirements in the currently effective version of PRC-024, PRC-024-3. Proposed Reliability Standard PRC-024-4 includes revisions to limit its applicability to synchronous generators and synchronous condensers only and remains as a protection-based standard. A new standard, PRC-029-1, is proposed as a true disturbance ride-through Reliability Standard with applicability to inverter-based resources.

In October 2023, FERC issued Order No. 901, which directed NERC to develop new or modified existing Reliability Standards that include new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. Project 2020-02 was one of three projects identified by NERC that must be completed and filed with FERC by November 4, 2024 to address Order No. 901 directives. At the December 2023 SC meeting, the SC approved waivers for Project 2020-02, allowing formal comment periods to be reduced from 45 days to 25 calendar days, and final ballot periods to be reduced from 10 days to as few as 5 calendar days.

The initial draft of the PRC-024-4 and PRC-029-1 drafts were posted for comment March 27, 2024- April 22, 2024. Comments have been reviewed and incorporated. Substantive changes were made to the PRC-029-1 draft based on comments received. Formal comment responses are available in the consideration of comments received document posted along with these additional drafts.

<u>Questions</u>

1. Provide any additional comments for the Drafting Team to consider, if desired.

   Comments:

Technical Rationale

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

PRC-024-4 – Frequency and Voltage Protection Settings for Synchronous Generators and Synchronous Condensers

General Rationale

The drafting team proposes to modify PRC-024-3 to retain the Reliability Standard as a protection-based standard with applicability to only synchronous generators and synchronous condensers. This proposal is a consequence of both the different natures of synchronous and inverter-based generation resources and several recent events exhibiting significant IBR ride-through deficiencies. The behavior of rotating synchronous generators during faults and other disturbances on the transmission system is well established and understood in comparison to IBR generation. The disturbance ride-through vulnerabilities of synchronous generators are pole slipping instability and undervoltage dropout of critical plant auxiliary equipment, leading to tripping of a generator. Pole slipping can be managed by active power dispatch and system condition constraints, and is outside the scope of PRC-024-3. Undervoltage dropout of critical auxiliary equipment is also outside the scope of PRC-024-3 because of complexities associated with auxiliary systems and how such equipment behaves under low voltage conditions.

The Project 2020-02 Standard Authorization Request (SAR) notes that auxiliary equipment has not posed a ride-through risk and the SAR specifically excludes modifications in PRC-024-3 for auxiliary equipment. Over-frequency protection, under-frequency protection, and voltage protection may or may not be applied to synchronous generating units. If applied however, settings should be coordinated between the needs of generating unit protection, reasonable expected excursions of system frequency and voltage in a straightforward fashion, e.g., as no-trip zones within PRC-024-3 attachments, as well as the coordination of generating unit capabilities, voltage regulating controls, and protection within PRC-019-2. Excitation and governing controls affect synchronous generator ride-through behavior to some degree but because of progressive improvement, standardization, and level of maturity of these controls, they are rarely if ever cause unnecessary tripping during disturbances.

In addition, there are other existing NERC standards to prevent unnecessary tripping of the generators during a system disturbance such as PRC-025-2 “Generator Relay Loadability”, and PRC-026-2 “Relay Performance During Stable Power Swings”. For these reasons, there is no need to impose actual disturbance ride-through requirements on synchronous units and only include restrictions for frequency and voltage protection setting ranges as maintained in PCR-024-4.

Rationale for Applicability Section (4.0)

Functional Entities (4.1)

The functional entity responsible for setting frequency, voltage, and volts per hertz protection for synchronous generators and synchronous condensers is the Generator Owner (GO) and Transmission

Owner (TO). Planning Coordinators (PC) are also retained as applicable entities but are only in the Quebec Interconnection. Modifications are proposed in PRC-024-4 to expand functional entity applicability to includes those Transmission Owners that apply protection, as listed in new Facility applicability section 4.2.2.

Facilities (4.2)

Applicability Facilities subparts in Section 4.1.1 were modified to restrict PRC-024-4 to synchronous generators. Section 4.2.2 was added as new subparts to identify which synchronous condensers and equipment.

Rationale for Requirements R1 through R4

Modifications were made to Requirements R1, R2, R3, and R4 to include the Transmission Owner as an functional entity applicable to each requirement.

Modifications were made to Requirements R1, R2, R3, and R4 to include language for synchronous condensers and to remove language that relates to inverter-based resource functionality (i.e., “cease injecting current”).

Technical Rationale

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

PRC-029-1 – Frequency and Voltage Ride-Through Requirements for Inverter-Based Generating Resources

General Rationale

The drafting team has created a new Reliability Standard (PRC-029-1) to address inverter-based resource (IBR) disturbance ride-through performance criteria. This proposal is a consequence of both the different natures of synchronous and inverter-based generation resources and several recent events exhibiting significant IBR ride-through deficiencies. The proposed PRC-029-1 coincides with certain ride-through requirements of IEEE 2800-2022 but is structured to follow language from FERC Order No. 901, which states that "NERC has the discretion to consider during its standards development process whether and how to reference IEEE standards in the new or modified Reliability Standards."[1]

The lack of standardization of IBR technology (equipment/controller behavior) has created reliability challenges associated with the interconnection of IBR facilities to the power grid. The nature of the fast switching of power electronics of IBR generation and the electronic interface to the transmission system is such that disturbance ride-through behavior is largely determined by manufacturer-specific equipment and controls system designs. These controls may be programmed but also have more restrictive limits on current, both in magnitude and duration. IBR responses to grid disturbances are highly controlled and managed by using fast switching of power electronics devices dependent upon manufacturer specific control system design that can be programmed in many ways and with various and concurrent ride-through performance objectives. Rather than attempting to restrict the myriad of control approaches, protections, and settings, it is more straightforward to require ride-through during defined frequency and voltage excursions.

In contrast to synchronous generation, the need for IBR ride-through requirements has been heightened by recent events during which IBRs have not met PRC-024-3 frequency and voltage ride-through expectations, often due to controls and protection only indirectly associated with the system voltage and frequency excursions. In addition to ride-through, there is the question of what IBRs should be doing as they ride-through. IBR responses to system disturbances can be beneficial or detrimental to both their own ride-through and system reliability, often depending on adjustable control settings. Thus, it is essential to set expectations on performance during ride-through as well as ride-through capability.

IBR do not provide inertia or short circuit contributions, unlike synchronous machines. The drafting team thinks that IBR should compensate for their lack of inertia and short circuit contributions with wider

[1] P 195, FERC Order No. 901; https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false; October 17, 2023

tolerances for frequency and voltage excursions. This is the reason for the differences in the frequency and voltage tables and graphs between the two standards.

The proposed PRC-029 must be understood as an event-based standard though it is also required to provide evidence of the ability to ride-through disturbance events by means of dynamic models and simulation results. Compliance with PRC-029 is determined chiefly though not exclusively from IBR ride-through performance during transmission system events in the field. An IBR becomes noncompliant with PRC-029 when an event in the field occurs that shows that one or more requirements were not satisfied. This intent is clarified by *Operations Assessment* as the Time Horizon designation of requirements R1-R5.

FERC Order No. 901 Directives

PRC-029-1 is proposed in consideration of directives from FERC Order No. 901 that were assigned to the Project 2020-02 drafting team. The following directives were assigned to this drafting team for inclusion in this Standards Project (paragraph numbers of the FERC Order are included for reference):

- Paragraph 190: "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults."
- Paragraph 190: "The new or modified Reliability Standards must require registered IBRs to continue to inject current and perform frequency support during a Bulk-Power System disturbance."
- Paragraph 190: "Any new or modified Reliability Standard must also require registered IBR generator owners and operators to prohibit momentary cessation in the must ride-through zone during disturbances."
- Paragraph 190: "NERC must submit new or modified Reliability Standards that establish IBR performance requirements, including requirements addressing frequency and voltage ride through, post-disturbance ramp rates, phase lock loop synchronization, and other known causes of IBR tripping or momentary cessation."
- Paragraph 193: "Therefore, we direct NERC through its standard development process to determine whether the new or modified Reliability Standards should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements."
- Paragraph 193: "Further, we direct NERC to ensure that any such exemption would be applicable for only existing equipment that is unable to meet voltage ride-through performance. When such existing equipment is replaced, the exemption would no longer apply, and the new equipment must comply with the appropriate IBR performance requirements specified in the Reliability Standards (e.g., voltage and frequency ride through, phase lock loop, ramp rates, etc.)."

- Paragraph 193: "Finally, we direct NERC, through its standard development process, to require the limited and documented exemption list (i.e., IBR generator owner and operator exemptions) to be communicated with their respective Bulk-Power System planners and operators (e.g., the IBR generator owner's or operator's planning coordinator, transmission planner, reliability coordinator, transmission operator, and balancing authority)."
- Paragraph 199: "Pursuant to section 215(d)(5) of the FPA, we modify the NOPR proposal. To the extent NERC determines that a limited and documented exemption for those registered IBRs currently in operation and unable to meet voltage ride-through requirements is appropriate due to their inability to modify their coordinated protection and control settings, we direct NERC to develop new or modified Reliability Standards to mitigate the reliability impacts to the Bulk-Power System of such an exemption."
- Paragraph 208: "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop and submit to the Commission for approval new or modified Reliability Standards that require post-disturbance ramp rates for registered IBRs to be unrestricted and not programmed to artificially interfere with the resource returning to a pre-disturbance output level in a quick and stable manner after a Bulk-Power System."
- Paragraph 209: "The proposed new or modified Reliability Standards must require registered IBRs to ride through momentary loss of synchronism during Bulk-Power System disturbances and require registered IBRs to continue to inject current into the Bulk-Power System at pre-disturbance levels during a disturbance, consistent with the IBR Interconnection Requirements Guideline and Canyon 2 Fire Event Report recommendations."
- Paragraph 209: "Related to ACP/SEIA's comment recommending to revise the directive to require generators to maintain synchronism where possible and continue to inject current to support system stability, we direct NERC, through its standard development process, to consider whether there are conditions that may limit generators to maintain synchronism."
- Paragraph 226: "Further, we believe that there is a need to have all of the directed Reliability Standards effective and enforceable well in advance of 2030 and direct NERC to ensure that the associated implementation plans sequentially stagger the effective and enforceable dates to ensure an orderly industry transition for complying with the IBR directives in this final rule prior to that date." (*pertains multiple projects*)

Rationale for Applicability Section (4.0)

Functional Entities (4.1)

The functional entity responsible for assuring acceptable ride-through performance of IBR is either the Generator Owner (GO) or, in the case of High-voltage Direct Current (VSC-HVDC) transmission facilities that are dedicated connections for IBR inverter-based resources to the BPS, the Transmission Owner (TO).

Facilities (4.2)

Applicability Facilities includes only those IBR that also meet NERC registration criteria. Language used within PRC-029-1 applicability only refers to IBR as a whole plant/facility. Consistent with FERC Order No. 901, IBR performance is based on the overall IBR plant and disturbance monitoring equipment requirements established under the proposed PRC-028-1. Requirements within PRC-029-1 do not apply to individual inverter units or measurements taken at individual inverter unit terminals.

Rationale for Requirement R1

The objective of Requirement R1 is to ensure that all applicable IBRs will ride through grid voltage disturbances consistent with the must ride-through zone and operation regions specified in **Attachment 1**. IBRs must be able to demonstrate ride-through performance, that they remain electrically connected, i.e., shall not trip, and continue to exchange current, i.e., shall not enter momentary cessation.

The drafting team determined that the definition of “must ride-through zones” and “operation regions” should be consistent with those terms as used within IEEE 2800-2022. Additionally, the team determined that the voltage thresholds of each operation region should be based on measurements taken on the high-side of the main power transformer in PRC-029-1, also consistent with IEEE 2800-2022.

Exceptions to **Attachment 1** performance criteria are allowable when 1) an IBR needs to trip to clear a fault within its zone of protection, and 2) a documented equipment limitation prevents an IBR from riding through the disturbance as permitted under Requirement R4.

When a grid disturbance occurs, such as a close-in fault or a relatively large switching event, the grid voltage may experience a rapid phase angle shift. In such cases, the phase displacement $\Delta\theta$ can be large enough to pose challenges for the PLL to track the terminal voltage, cause control instability within the inverter, such as the inner current control loop or the DC link control loop, and even lead to tripping of the inverter due to the malfunction of the controls.

Since phase angle jumps are common occurrences on the BPS, this standard requires the IBR to be designed and operated to ride-through a minimum phase angle jump of 25 electrical degrees. This is a typical value and aligns with the requirement in IEEE 2800 2022.

Some IBR equipment has PLL loss of synchronism protection, referring to a protective function that operates when the angle displacement $\Delta\theta$ exceeds a threshold for a predetermined period of time (on the order of a couple of milliseconds). Historically, this protection has been used by some inverter manufacturers, especially for inverters in distribution systems. For the IBR connected to the BPS, this protection function should be disabled. If it is enabled, the phase angle jump protection setting should be configured such that the IBR shall only trip to prevent equipment damage.

Rationale for Requirement R2

In addition to having minimum voltage ride-through capability specified in Requirement R1, all applicable IBRs are also required to adhere to certain voltage ride-through performance criteria during system disturbances. Acceptable performance criteria depend on the operation region that an IBR is presently in or when in transition from one operation region to another operation region. Requirement R2 includes specific performance criteria and is needed to assure consistent IBR performance within and each operation region in **Attachment 1** and when in transition between regions.

Rationale for Requirement R2.1

This subpart of Requirement 2 ensures, when the voltage at the high-side of the main power transformer (MPT) recovers to the Continuous Operation Region from either the Mandatory Operation Region or the Permissive Operation Region, an IBR is expected to deliver the pre-disturbance level of active power or available active power, whichever is less. This requires an IBR to exit the "High Voltage Ride Through (HVRT)" or "Low Voltage Ridge Through (LVRT)" modes properly such that it does not cause reduction in the active power when the system already recovers the voltage within the Continuous Operation Region.

When the voltage at the high-side of the MPT is greater than 0.9 per-unit and less than 0.95 per-unit, IBRs are expected to exit the LVRT mode and come back to "normal operating mode". If an IBR has a default total current limit of 1.0 per-unit, the apparent power production of an IBR will be limited to be below 1.0 per-unit (e.g., the per-unit value of IBR terminal voltage). In such case, IBR needs to configure a preference setting, either to maintain pre-disturbance active power or maximize the reactive power in order to further help with voltage recovery, according to requirements specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Rationale for Requirement R2.2

This subpart of Requirement 2 ensures when the voltage at the high-side of the MPT is within the Mandatory Operation Region, IBRs are expected to enter the HVRT and LVRT mode such that it will inject or absorb reactive current proportional to the level of terminal voltage deviations it measures. IBR shall follow Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specified certain magnitude of reactive power response to voltage changes, if available.

By default, reactive current prioritization shall be configured unless Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires active power priority.

Rationale for Requirement R2.3

This subpart of Requirement 2 ensures when the voltage at the high-side of the MPT is within the permissive operation region, IBRs are allowed to enter the current block mode to avoid tripping off from the grid. The drafting team takes into consideration the physical operational capability of the power electronics devices under such low voltage condition. However, the IBR facility shall restart current exchange in less than or equal to five cycles of positive sequence voltage retraining to a continuous operation region or mandatory operation region.

Rationale for Requirement R2.4

This subpart of Requirement 2 ensures when a fault is cleared on the transmission system, the voltage regulators of connected IBRs must adjust the reactive current injection to restore the transmission system voltage to the pre-disturbance voltage as defined by the automatic voltage regulator (AVR) setpoint. The drafting team acknowledges that tuning of the AVR requires a balance between multiple competing physical factors, e.g., rise time, overshoot, and transient stability. However, it is anticipated that IBR controls will be tuned to allow for a stable post-disturbance voltage recovery without causing excessive overshoot or undershoot of the setpoint. When such overshoots do occur, they must not exceed the magnitude and duration of the applicable table given in **Attachment 1**. Furthermore, this standard anticipates that control system tuning to prevent such over/under voltages will focus on the speed at which the controller responds to setpoint changes rather than on the magnitude of the reactive current response. For example, reductions in k-factor to prevent over/under voltages should only be considered as a last resort.

Rationale for Requirement R2.5

This subpart of Requirement 2 ensures that IBR returns to effective pre-disturbance operation unless otherwise specified or needed by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Must Ride-through

Rationale for Requirement R3

The objective of Requirement R3 is to ensure that IBRs remain electrically connected, synchronized, and exchanging current, that is, continuing to operate during a frequency excursion event.

Grid frequency reflects the balance of system generation and load. A system event that causes a generation/load imbalance will cause system frequency to deviate from nominal. The system may experience an over-frequency event (in the case of more generation than load) or an under-frequency event (in the case of less generation than load). Inertia resists the deviation from nominal frequency, giving the operators additional time to rebalance generation and load. System inertia depends on the amount of rotating mass connected to the system (such as the synchronous generators or motors). The larger the system inertia, the slower the system frequency will deviate from the nominal value and the lower the grid Rate Of Change Of Frequency (ROCOF), giving more time to try to rebalance generation and load. Also, higher system inertia may minimize the risk of Cascading generation loss caused by the operation of generator frequency protection.

A reduction in system inertia is an inevitable consequence of a power system transiting toward more IBR and less synchronous generators. As discussed in the previous paragraph, less system inertia means the frequency will deviate from the nominal value more quickly during a generation/load imbalance event and will expose the system to a higher ROCOF. A wider frequency ride-through capability for IBR may be required to avoid the risk of widespread tripping. To reduce the risk of widespread IBR tripping during frequency disturbances, and more generally to ensure the reliability of future grids with high IBR penetration, the drafting team proposes a 6-second frequency ride-through capability requirement for frequencies in the ranges of 61.8Hz to 64Hz or 57.0Hz to 56.0Hz range. The proposed 6-second time frame of the frequency ride-through capability requirement is beyond the IEEE 2800 standard frequency ride-through requirement and beyond frequency ride-through requirements for synchronous machines under PRC-024.

IBRs lack the inertia and short circuit contributions of synchronous machines. To compensate for the lack of inertia and short circuit contributions, they should have wider tolerances for frequency and voltage excursions to meet the needs of future power systems with a higher percentage of IBR. Synchronous resources are more sensitive to frequency deviations than IBR resources. All IBR resources (except for type 3 wind turbines) interface to the grid through fast switching of power electronics devices. These power electronic devices are much less sensitive to the transmission system frequency excursion than non-hydraulic turbine synchronous resources (steam turbines and combustion turbines). In the case of the non-hydraulic turbine synchronous resources, the turbine is usually considered to be more restrictive than the generator in limiting IBR frequency ride-through because of possible mechanical resonances in the many stages of turbine blades. Off-nominal frequencies may bring blade vibrational frequencies closer to a mechanical resonate frequency and cause damage due to the vibration stresses. However, inverter-interfaced-IBR does not share this vibrational failure mode. Therefore, IBR should be capable of riding through the increased proposed 6-second frequency ride-through requirement without risk of equipment damage or need for frequency protection to operate.

Requirement R3 does not prescribe specific frequency protection settings for IBR equipment. IBR frequency protection settings should only be set to protect the IBR from damage caused by operation at off-nominal frequency. An IBR owner must ensure that the IBR frequency protection does not prevent an IBR from meeting the R3 ride-through requirement.

This standard requires that IBRs remain electrically connected and continue to exchange current during a frequency excursion event in which the frequency remains within the must ride-through zone according to **Attachment 3** and while the absolute ROCOF magnitude is less than or equal to 5 Hz/second. Some IBR controllers and their ability to remain electrically connected and continue to exchange current with the grid are sensitive to ROCOF during a frequency excursion event. If needed to maintain the stability of the IBR or prevent equipment damage, the R3 requirement allows the IBR to trip for an absolute ROCOF exceeding 5Hz/sec within the must ride-through zone as shown in **Attachment 2**. Failure to ride-through due to ROCOF exceeding 5Hz/sec shall only be allowed during a generator/load imbalance event that causes the frequency to deviate from nominal.

The ROCOF protection should not operate at the onset of a fault, during a fault, or at fault clearance, i.e., it should be disabled for faults. The IBR shall ride-through any system disturbance while the voltage at the high side of the main power transformer remains within the must ride-through zones as specified in **Attachment 1**. Furthermore, to reduce the risk of IBR tripping on ROCOF protection, ROCOF shall be calculated as the average rate of change for multiple calculated system frequencies for some time greater than or equal to 0.1 seconds.

Rationale for Requirement R4

The objective of Requirement R4 is to ensure legacy IBR are able to obtain an exemption to the voltage ride-through requirements if hardware replacements or other costly upgrades would be necessary to comply with Requirements R1 or Requirement R2. This provision allows such exemptions as long as such limitations are documented and communicated to the Planning Coordinator, Transmission Planner, and Reliability Coordinator of the respective footprints in which the IBR project is located. The Planning Coordinator, Transmission Planner, and Reliability Coordinator will then need to take the voltage ride-through limitations into account in planning and operations.

Limitations must not be construed as complete exemptions from the applicable **Attachment 1** table but must be specific as to which voltage band(s) and associated duration(s) cannot be satisfied or specific as to the number of cumulative voltage deviations within a ten-second time period that the equipment can ride-through if less than four. Limitation descriptions should identify the specific equipment and explain the characteristic(s) of that equipment that prevent ride-through. If any equipment limitation is removed or otherwise corrected, it is likewise necessary to communicate to the Planning Coordinator, Transmission Planner, and Reliability Coordinator of this.

FERC Order No. 901 states that this provision would be limited to exempting “certain registered IBRs from voltage ride-through performance requirements.” This is the reason that no similar provisions are included for exemptions for frequency or rate-of-change-of-frequency (ROCOF) ride-through requirements per R3.

Technical Rationale

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

PRC-029-1 – Frequency and Voltage Ride-Through Requirements for Inverter-Based Generating Resources

General Rationale

The drafting team has created a new Reliability Standard (PRC-029-1) to address inverter-based resource (IBR) disturbance ride-through performance criteria. This proposal is a consequence of both the different natures of synchronous and inverter-based generation resources and several recent events exhibiting significant IBR ride-through deficiencies. The proposed PRC-029-1 coincides with certain ride-through requirements of IEEE 2800-2022 but is structured to follow language from FERC Order No. 901, which states that "NERC has the discretion to consider during its standards development process whether and how to reference IEEE standards in the new or modified Reliability Standards."[1]

The lack of standardization of IBR technology (equipment/controller behavior) has created reliability challenges associated with the interconnection of IBR facilities to the power grid. The nature of the fast switching of power electronics of IBR generation and the electronic interface to the transmission system is such that disturbance ride-through behavior is largely determined by manufacturer-specific equipment and controls system designs. These controls may be programmed but also have more restrictive limits on current, both in magnitude and duration. IBR responses to grid disturbances are highly controlled and managed by using fast switching of power electronics devices dependent upon manufacturer specific control system design that can be programmed in many ways and with various and concurrent ride-through performance objectives. Rather than attempting to restrict the myriad of control approaches, protections, and settings, it is more straightforward to require ride-through during defined frequency and voltage excursions.

In contrast to synchronous generation, the need for IBR ride-through requirements has been heightened by recent events during which IBRs have not met PRC-024-3 frequency and voltage ride-through expectations, often due to controls and protection only indirectly associated with the system voltage and frequency excursions. In addition to ride-through, there is the question of what IBRs should be doing as they ride-through. IBR responses to system disturbances can be beneficial or detrimental to both their own ride-through and system reliability, often depending on adjustable control settings. Thus, it is essential to set expectations on performance during ride-through as well as ride-through capability.

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tolerances for frequency and voltage excursions. This is the reason for the differences in the frequency and voltage tables and graphs between the two standards.

The proposed PRC-029 must be understood as an event-based standard~~.~~ though it is also required to provide evidence of the ability to ride-through disturbance events by means of dynamic models and simulation results. Compliance with PRC-029 is determined chiefly though not exclusively from IBR ride-through performance during transmission system events in the field~~ and not from interconnection studies, transmission planning studies, operational planning studies, or from IBR models.~~. An IBR becomes noncompliant with PRC-029~~ only~~ when an event in the field occurs that shows that one or more requirements were not satisfied. This intent is clarified by *Operations Assessment* as the Time Horizon designation of requirements R1-R5.

FERC Order No. 901 Directives

PRC-029-1 is proposed in consideration of directives from FERC Order No. 901 that were assigned to the Project 2020-02 drafting team. The following directives were assigned to this drafting team for inclusion in this Standards Project (paragraph numbers of the FERC Order are included for reference):

- Paragraph 190: "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults."
- Paragraph 190: "The new or modified Reliability Standards must require registered IBRs to continue to inject current and perform frequency support during a Bulk-Power System disturbance."
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- Paragraph 193: "Therefore, we direct NERC through its standard development process to determine whether the new or modified Reliability Standards should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements."
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must comply with the appropriate IBR performance requirements specified in the Reliability Standards (e.g., voltage and frequency ride through, phase lock loop, ramp rates, etc.)."

- Paragraph 193: "Finally, we direct NERC, through its standard development process, to require the limited and documented exemption list (i.e., IBR generator owner and operator exemptions) to be communicated with their respective Bulk-Power System planners and operators (e.g., the IBR generator owner's or operator's planning coordinator, transmission planner, reliability coordinator, transmission operator, and balancing authority)."
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- Paragraph 209: "The proposed new or modified Reliability Standards must require registered IBRs to ride through momentary loss of synchronism during Bulk-Power System disturbances and require registered IBRs to continue to inject current into the Bulk-Power System at pre-disturbance levels during a disturbance, consistent with the IBR Interconnection Requirements Guideline and Canyon 2 Fire Event Report recommendations."
- Paragraph 209: "Related to ACP/SEIA's comment recommending to revise the directive to require generators to maintain synchronism where possible and continue to inject current to support system stability, we direct NERC, through its standard development process, to consider whether there are conditions that may limit generators to maintain synchronism."
- Paragraph 226: "Further, we believe that there is a need to have all of the directed Reliability Standards effective and enforceable well in advance of 2030 and direct NERC to ensure that the associated implementation plans sequentially stagger the effective and enforceable dates to ensure an orderly industry transition for complying with the IBR directives in this final rule prior to that date." (*pertains multiple projects*)

Rationale for Applicability Section (4.0)

Functional Entities (4.1)

The functional entity responsible for assuring acceptable ride-through performance of IBR is either the Generator Owner (GO) ~~and~~or, in the case of High-voltage Direct Current (VSC-HVDC) transmission facilities that are dedicated connections for IBR inverter-based resources to the BPS, the Transmission Owner (TO).

Facilities (4.2)

Applicability Facilities includes only those IBR that also meet NERC registration criteria. Language used within PRC-029-1 applicability only refers to IBR as a whole plant/facility. Consistent with FERC Order No. 901, IBR performance is based on the overall IBR plant and disturbance monitoring equipment requirements established under the proposed PRC-028-1. Requirements within PRC-029-1 do not apply to individual inverter units or measurements taken at individual inverter unit terminals.

Rationale for Requirement R1

The objective of Requirement R1 is to ensure ~~an~~that all applicable ~~IBR~~IBRs will ride~~-~~ through ~~a~~ grid voltage ~~disturbance~~disturbances consistent with the ~~no-trip~~must ride-through zone and ~~Operation Regions~~operation regions specified in Attachment 1. ~~IBR~~IBRs must be able to demonstrate ride-through performance, that they remain electrically connected, i.e., shall not trip, and continue to exchange current, i.e., shall not enter momentary cessation.

The drafting team determined that the definition of "~~no-trip~~must ride-through zones" and "~~Operation Regions~~operation regions" should be consistent with those terms as used within IEEE 2800-2022. Additionally, the team determined that the voltage thresholds of each ~~Operation Region are~~operation region should be based on measurements taken on the high-side of the main power transformer in PRC-029-1, also consistent with IEEE 2800-2022.

Exceptions to Attachment 1 performance criteria are allowable when 1) an IBR needs to trip to clear a fault within its zone of protection, and 2) a documented equipment limitation prevents an IBR from riding through the disturbance ~~in accordance with~~as permitted under Requirement ~~R6~~R4.

When a grid disturbance occurs, such as a close-in fault or a relatively large switching event, the grid voltage may experience a rapid phase angle shift. In such cases, the phase displacement $\Delta\theta$ can be large enough to pose challenges for the PLL to track the terminal voltage, cause control instability within the inverter, such as the inner current control loop or the DC link control loop, and even lead to tripping of the inverter due to the malfunction of the controls.

Since phase angle jumps are common occurrences on the BPS, this standard requires the IBR to be designed and operated to ride-through a minimum phase angle jump of 25 electrical degrees. This is a typical value and aligns with the requirement in IEEE 2800 2022.

Some IBR equipment has PLL loss of synchronism protection, referring to a protective function that operates when the angle displacement $\Delta\theta$ exceeds a threshold for a predetermined period of time (on the order of a couple of milliseconds). Historically, this protection has been used by some inverter manufacturers, especially for inverters in distribution systems. For the IBR connected to the BPS, this protection function should be disabled. If it is enabled, the phase angle jump protection setting should be configured such that the IBR shall only trip to prevent equipment damage.

Rationale for Requirement R2

In addition to having minimum voltage ride-through capability specified in Requirement R1, ~~an~~all applicable ~~IBR is~~IBRs are also required to adhere to certain voltage ride-through performance criteria during ~~a~~ system ~~disturbance~~disturbances. Acceptable performance criteria ~~is dependent~~depend on the ~~Operation Region~~operation region that an IBR is presently in~~,~~ or ~~it's change~~when in transition from one ~~Operation Region~~operation region to another ~~Operation Region~~operation region. Requirement R2 includes specific performance criteria and is needed to assure consistent IBR performance ~~during~~within and each ~~Operation Region~~operation region in Attachment 1 and when in transition between regions.

Rationale for Requirement R2.1

This subpart of Requirement 2 ensures, when the voltage at the high-side of the main power transformer (MPT) recovers to the Continuous Operation Region from either the Mandatory Operation Region or the Permissive Operation Region, an IBR is expected to deliver the pre-disturbance level of active power or available active power, whichever is less. This requires an IBR to exit the "High Voltage Ride Through (HVRT)" or "Low Voltage Ridge Through (LVRT)" modes properly such that it does not cause reduction in the active power when the system already recovers the voltage within the Continuous Operation Region.

When the voltage at the high-side of the MPT is greater than 0.9 per-unit and less than 0.95 per-unit, IBRs are expected to exit the LVRT mode and come back to "normal operating mode". If an IBR has a default total current limit of 1.0 per-unit, the apparent power production of an IBR will be limited to be below 1.0 per-unit (e.g., the per-unit value of IBR terminal voltage). In such case, IBR needs to configure a preference setting, either to maintain pre-disturbance active power or maximize the reactive power in order to further help with voltage recovery, according to requirements specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Rationale for Requirement R2.2

This subpart of Requirement 2 ensures when the voltage at the high-side of the MPT is within the Mandatory Operation Region, IBRs are expected to enter the HVRT and LVRT mode such that it will inject or absorb reactive current proportional to the level of terminal voltage deviations it measures. IBR shall follow Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specified certain magnitude of reactive power response to voltage changes, if available.

By default, reactive current prioritization shall be configured unless Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires active power priority.

Rationale for Requirement R2.3

This subpart of Requirement 2 ensures when the voltage at the high-side of the MPT is within the permissive operation region, IBRs are allowed to enter the current block mode to avoid tripping off from the grid. The drafting team takes into consideration the physical operational capability of the power electronics devices under such low voltage condition. However, the IBR facility shall restart current exchange in less than or equal to five cycles of positive sequence voltage retraining to a continuous operation region or mandatory operation region.

Rationale for Requirement R2.4

This subpart of Requirement 2 ensures when a fault is cleared on the transmission system, the voltage regulators of connected IBRs must adjust the reactive current injection to restore the transmission system voltage to the pre-disturbance voltage as defined by the automatic voltage regulator (AVR) setpoint. The drafting team acknowledges that tuning of the AVR requires a balance between multiple competing physical factors, e.g., rise time, overshoot, and transient stability. However, it is anticipated that IBR controls will be tuned to allow for a stable post-disturbance voltage recovery without causing excessive overshoot or undershoot of the setpoint. When such overshoots do occur, they must not exceed the magnitude and duration of the applicable table given in Attachment 1. Furthermore, this standard anticipates that control system tuning to prevent such over/under voltages will focus on the speed at which the controller responds to setpoint changes rather than on the magnitude of the reactive current response. For example, reductions in k-factor to prevent over/under voltages should only be considered as a last resort.

Rationale for Requirement R2.~~4~~5

This subpart of Requirement 2 ensures that IBR returns to effective pre-disturbance operation unless otherwise specified or needed by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

~~*Rationale for Requirement R2.5*~~

~~This subpart of Requirement 2 ensures that voltage protection settings of IBR are based on maximum equipment capabilities rather than settings based directly on, or just outside, of the no-trip zone.~~

Must Ride-through

Rationale for Requirement R3

The objective of Requirement R3 is to ~~provide transient overvoltage ride-through for IBR during the non-fault switching event. Voltage transients are commonly occurring on the BPS due to switching actions, fault clearing, lightning, etc. IBR shall ride-through the transient overvoltage condition specified in **Attachment 2** during the non-fault switching events in the transmission systems. During this transient overvoltage event, IBRs should continue to inject current, but it does not have to respond to transient overvoltage, i.e., enter reactive priority mode and/or change magnitude of current output.~~

~~If necessary, IBRs may operate in current blocking mode, when instantaneous voltage exceeds 1.2 p.u., to help~~ ensure ~~stable response~~ that ~~does not lead to tripping and to eliminate the IBR as a possible cause for the overvoltage. If IBRs operate in the current blocking mode, it shall restart current exchange in less than or equal to five cycles following instantaneous voltage falling below, and remaining below, 1.2 p.u. This is different than momentary cessation, which involves a resource returning over a longer time frame with a specified delay and ramp rate.~~

~~The drafting team notes that IBR should not be set to trip on an instantaneous, unfiltered voltage measurements, except due to known equipment limitations.~~

~~Rationale for Requirement R4~~

~~The objective of Requirement R4 is to ensure that IBR remains~~IBRs remain electrically connected, synchronized, and exchanging current~~-~~, that is, continuing to operate during a frequency excursion event.

Grid frequency reflects the balance of system generation and load. A system event that causes a generation/load imbalance will cause system frequency to deviate from nominal. The system may experience an over-frequency event (in the case of more generation than load) or an under-frequency event (in the case of less generation than load). Inertia resists the deviation from nominal frequency, giving the operators additional time to rebalance generation and load. System inertia depends on the amount of rotating mass connected to the system (such as the synchronous generators or motors). The larger the system inertia, the slower the system frequency will deviate from the nominal value and the lower the grid Rate Of Change Of Frequency (ROCOF), giving more time to try to rebalance generation and load. Also, higher system inertia may minimize the risk of Cascading generation loss caused by the operation of generator frequency protection.

A reduction in system inertia is an inevitable consequence of a power system transiting toward more IBR and less synchronous generators. As discussed in the previous paragraph, less system inertia means the frequency will deviate from the nominal value more quickly during a generation/load imbalance event and will expose the system to a higher ROCOF. A wider frequency ride-through capability for IBR may be required to avoid the risk of widespread tripping. To reduce the risk of widespread IBR tripping during frequency disturbances, and more generally to ensure the reliability of future grids with high IBR penetration, the drafting team proposes a 6-second frequency ride-through capability requirement for frequencies in the ranges of 61.8Hz to 64Hz or 57.0Hz to 56.0Hz range. The proposed 6-second time frame of the frequency ride-through capability requirement is beyond the IEEE 2800 standard frequency ride-through requirement and beyond frequency ride-through requirements for synchronous machines under ~~proposed~~ PRC-024~~-4~~.

~~IBR lacks~~IBRs lack the inertia and short circuit contributions of synchronous machines. To compensate for the lack of inertia and short circuit contributions, they should have wider tolerances for frequency and voltage excursions to meet the needs of future power ~~system~~systems with a higher percentage of IBR. Synchronous resources are more sensitive to frequency deviations than IBR resources. All IBR resources (except for type 3 wind turbines) interface to the grid through fast switching of power electronics devices. These power electronic devices are much less sensitive to the transmission system frequency excursion than non-hydraulic turbine synchronous resources (steam turbines and combustion turbines). In the case of the non-hydraulic turbine synchronous resources, the turbine is usually considered to be more restrictive than the generator in limiting IBR frequency ride-through because of possible mechanical resonances in the many stages of turbine blades. Off-nominal frequencies may bring blade vibrational frequencies closer to a mechanical resonate frequency and cause damage due to the vibration stresses. However, inverter-interfaced-IBR does not share this vibrational failure mode. Therefore, IBR should be capable of riding through the increased proposed 6-second frequency ride-through requirement without risk of equipment damage or need for frequency protection to operate.

Requirement ~~R4~~R3 does not prescribe specific frequency protection settings for IBR equipment. IBR frequency protection settings should only be set to protect the IBR from damage caused by operation at off-nominal frequency. An IBR owner must ensure that the IBR frequency protection does not prevent an IBR from meeting the ~~R4~~R3 ride-through requirement.

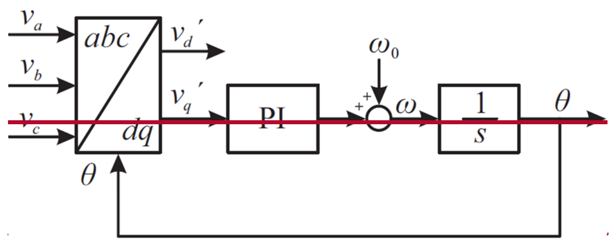
This standard requires that ~~IBR remains~~IBRs remain electrically connected and ~~continues~~continue to exchange current during a frequency excursion event in which the frequency remains within the ~~no-trip~~must ride-through zone~~\~~ according to Attachment 3 and while the absolute ROCOF magnitude is less than or equal to 5 Hz/second. Some IBR controllers and their ability to remain electrically connected and continue to exchange current ~~to~~with the grid are sensitive to ROCOF during a frequency excursion event. If needed to maintain the stability of the IBR or prevent equipment damage, the ~~R4~~R3 requirement allows the IBR to trip for an absolute ROCOF exceeding 5Hz/sec within the ~~no-trip~~must ride-through zone as shown in Attachment ~~3~~2. Failure to ride-through due to ROCOF exceeding 5Hz/sec shall only be allowed during a generator/load imbalance event that causes the frequency to deviate from nominal.

The ROCOF protection should not operate at the onset of a fault, during a fault, or at fault clearance, i.e., it should be disabled for faults. The IBR shall ride-through any system disturbance while the voltage at the high side of the main power transformer remains within the ~~no-trip~~must ride-through zones as specified in Attachment 1. Furthermore, to reduce the risk of IBR tripping on ROCOF protection, ROCOF shall be calculated as the average rate of change for multiple calculated system frequencies for some time greater than or equal to 0.1 seconds.

Rationale for Requirement ~~R5~~R4

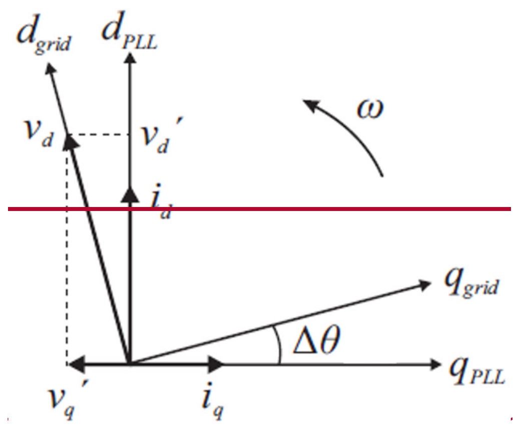
The objective of Requirement ~~R5 is to ensure IBR remains electrically connected and exchanging current during instantaneous positive sequence voltage phase angle changes initiated by certain non-fault switching events.~~

~~Unlike synchronous generators, for which the synchronization mechanism to the grid is naturally preserved by the inertia, the grid following voltage source inverters (VSI) used for the majority of existing IBR facilities are equipped with the Phase-lock loop (PLL) device for synchronization purposes. A typical synchronous reference frame PLL schematic is given in Fig. 1, where the three-phase voltages in the abc reference frame (v_a, v_b, and v_c) are transformed to the dq frame (v_d' and v_q') by the Park's transformation and the phase angle θ is controlled by a feedback loop that regulates the q component to zero.~~



~~**Figure 1: Schematic Diagram of a Synchronous Reference Frame PLL**~~

~~When the inverter operates in the steady state, it is locked to the grid voltage via the PLL, assuming the PI controller is well tuned. In this case the phase displacement between the grid voltage and that measured by the PLL, Δθ is zero, as shown in Fig. 2.~~



~~**Figure 2: Phasor Diagram of Grid Voltage and Current**~~

~~When a grid disturbance occurs, such as a close-in fault or a relatively large switching event, the grid voltage may experience a rapid phase angle shift. In such cases, the phase displacement Δθ can be large enough to pose challenges for the PLL to track the terminal voltage, cause control instability within the inverter, such as the inner current control loop or the DC link control loop, and even lead to tripping of the inverter due to the malfunction of the controls.~~

~~Since phase angle jumps are common occurrences on the BPS, this standard requires the IBR to be designed and operated to ride-through a minimum phase angle jump of 25 electrical degrees. This is a typical value and aligns with the requirement in IEEE 2800-2022. Furthermore, for a phase angle jump of 25 degrees or more, the IBR shall only trip to prevent equipment damage.~~

~~Some IBR equipment has PLL loss of synchronism protection, referring to a protective function that operates when the angle displacement Δθ exceeds a threshold for a predetermined period of time (on the order of a couple of milliseconds). Historically, this protection has been used by some inverter manufacturers, especially for inverters in distribution systems. For the IBR connected to the BPS, this protection function should be disabled. If it is enabled, the phase angle jump protection setting shall be configured such that the IBR shall only trip to prevent equipment damage.~~

~~**Rationale for Requirement R6**~~

~~The objective of Requirement R5~~R4 is to ensure legacy IBR ~~may need~~are able to obtain an exemption to the voltage ride-through requirements if hardware replacements or other costly upgrades would be necessary to comply with Requirements R1 or Requirement R2. This provision allows such exemptions as long as such limitations are documented and communicated to the Planning Coordinator, Transmission Planner, and Reliability Coordinator of the respective footprints in which the IBR project is located. The Planning Coordinator, Transmission Planner, and Reliability Coordinator will then need to take the voltage ride-through limitations into account in planning and operations.

Limitations must not be construed as complete exemptions from the applicable **Attachment 1** table but must be specific as to which voltage band(s) and associated duration(s) cannot be satisfied or specific as to the number of cumulative voltage deviations within a ten-second time period that the equipment can ride-through if less than four. Limitation descriptions should identify the specific equipment and explain the characteristic(s) of that equipment that prevent ride-through. If any equipment limitation is removed or otherwise corrected, it is likewise necessary to communicate to the Planning Coordinator, Transmission Planner, and Reliability Coordinator of this.

FERC Order No. 901 states that this provision would be limited to exempting “certain registered IBRs from voltage ride-through performance requirements.” This is the reason that no similar provisions are included for exemptions for frequency~~,~~, or rate-of-change-of-frequency (ROCOF) ~~,phase angle change~~ ride-through requirements per R3.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
PRC-024-4

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-024-4. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to BulkPower System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to BulkPower System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System. However, violation of a medium risk requirement is unlikely to lead to Bulk- Power System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BulkPower System, or the ability to effectively monitor, control, or restore the BulkPower System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

The VRF did not change from the previously FERC approved PRC-024-3 Reliability Standard.

VSLs for PRC-024-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to set its applicable frequency protection so that it does not trip according to Requirement R1.

VSL Justifications for PRC-024-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement adds a functional entity. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-024-4, Requirement R1	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

The VRF did not change from the previously FERC approved PRC-024-3 Reliability Standard.

VSLs for PRC-024-4, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
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 according to Requirement R2.

VSL Justifications for PRC-024-4, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement adds a functional entity. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-024-4, Requirement R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

The VRF did not change from the previously FERC approved PRC-024-3 Reliability Standard.

VSLs for PRC-024-4, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner or Transmission 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 or Transmission 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 or Transmission 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 or Transmission 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 or Transmission Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.

VSL Justifications for PRC-024-4, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement adds a functional entity. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for PRC-024-4, Requirement R3	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

The VRF did not change from the previously FERC approved PRC-024-3 Reliability Standard.

VSLs for PRC-024-4, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner or Transmission Owner provided its protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner or provided protection settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner or Transmission Owner failed to provide its protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner failed to provide protection settings within 150 calendar days of a written request.

VSL Justifications for PRC-024-4, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement adds a functional entity. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-024-4, Requirement R4	
Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

Violation Risk Factor and Violation Severity Level Justifications

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
PRC-029-1

This document provides the drafting team's (DT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-029-1. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The DT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to BulkPower System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to BulkPower System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System. However, violation of a medium risk requirement is unlikely to lead to Bulk- Power System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BulkPower System, or the ability to effectively monitor, control, or restore the BulkPower System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for PRC-029-1, Requirement R1	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate as applicable generating resources must be able to ride-through system disturbances. Failure to ride-through has been documented in multiple NERC reports leading to exacerbated system conditions, resulting in the electrical disconnecting of additional generation and widespread outages.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Similar requirements in PRC-024-3 are identified as Medium but are based on equipment protection setting documentation rather than actual, recorded performance during a grid disturbance. Therefore, this VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner or Transmission Owner failed to demonstrate the capability of each applicable facility to Ride-through in accordance with Attachment 1, except for those conditions identified in Requirement R1.	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable facility adhered to Ride-through requirements in accordance with Attachment 1, except for those conditions identified in Requirement R1.

VSL Justifications for PRC-029-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R1	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R2	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate as applicable generating resources must be able to ride-through system disturbances. Failure to ride-through has been documented in multiple NERC reports leading to exacerbated system conditions, resulting in the electrical disconnecting of additional generation and widespread outages.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion	Similar requirements in PRC-024-3 are identified as Medium but are based on equipment protection setting

VRF Justifications for PRC-029-1, Requirement R2	
Proposed VRF	**High**
Guideline 3- Consistency among Reliability Standards	documentation rather than actual, recorded performance during a grid disturbance. Therefore, this VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner or Transmission Owner failed to demonstrate the capability of each applicable facility to adhere to performance requirements during voltage excursions, as specified in Requirement R2.	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable facility adhered to performance requirements during voltage excursions, as specified in Requirement R2.

VSL Justifications for PRC-029-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering

VSL Justifications for PRC-029-1, Requirement R2	
Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R3	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of High is appropriate that if violated, it would be expected to adversely affect the electrical state or capability of the Bulk-Power System.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**

The Generator Owner or Transmission Owner failed to demonstrate the capability of each applicable facility to Ride-through in accordance with Attachment 2.	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable facility adhered to Ride-through requirements in accordance with Attachment 2.

VSL Justifications for PRC-029-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

VSL Justifications for PRC-029-1, Requirement R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R4	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate that if violated, it would not be expected to adversely affect the electrical state or capability of the Bulk-Power System.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of Lower VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a Lower VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VRF Justifications for PRC-029-1, Requirement R4	
Proposed VRF	**Lower**
than One Obligation	

VSLs for PRC-029-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) more than 30 calendar days but less than or equal to 60 calendar days after the change to the equipment. OR The Generator Owner or Transmission Owner provided a copy to the applicable entities as detailed in R4.2 more than 12 months but less than or equal to 15	The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) more than 60 calendar days but less than or equal to 90 calendar days after the change to the equipment. OR The Generator Owner or Transmission Owner provided a copy to the applicable entities as detailed in R4.2 more than 15 months but less than or equal to 18	The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) more than 90 calendar days but less than or equal to 120 calendar days after the change to the equipment. OR The Generator Owner or Transmission Owner provided a copy to the applicable entities as detailed in R4.2 more than 18 months but less than or equal to 21	The Generator Owner or Transmission Owner failed to document complete information for facilities identified with known hardware limitations that prevent the facility from meeting voltage Ride-through criteria as detailed in Requirements R1 or R2. OR The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the limiting equipment but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) more than 120 calendar days after the change to the equipment.

months after the effective date of R4.	months after the effective date of R4.	months after the effective date of R4.	OR The Generator Owner or Transmission Owner failed to provide a copy to the applicable entities as detailed in R4.2 within 24 months after the effective date of R4.

VSL Justifications for PRC-029-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R4	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

Violation Risk Factor and Violation Severity Level Justifications

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
PRC-029-1

This document provides the ~~standard~~ drafting team's (~~S~~DT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-029-1. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The ~~S~~DT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to BulkPower System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to BulkPower System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System. However, violation of a medium risk requirement is unlikely to lead to Bulk- Power System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BulkPower System, or the ability to effectively monitor, control, or restore the BulkPower System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for PRC-029-1, Requirement R1	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate as applicable generating resources must be able to ride-through system disturbances. Failure to ride-through has been documented in multiple NERC reports leading to exacerbated system conditions, resulting in the electrical disconnecting of additional generation and widespread outages.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Similar requirements in PRC-024-3 are identified as Medium but are based on equipment protection setting documentation rather than actual, recorded performance during a grid disturbance. Therefore, this VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
~~A~~The Generator Owner or Transmission Owner failed to demonstrate the capability of each applicable facility to Ride-through in accordance with Attachment 1, except for those conditions identified in Requirement R1.~~N/A~~	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable facility adhered to Ride-through requirements in accordance with Attachment 1, except for those conditions identified in ~~IBR remains electrically connected and continued to exchange current in accordance with Attachment 1, unless needed to clear a fault, in accordance with~~ Requirement R1.

VSL Justifications for PRC-029-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R1	
for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R2	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate as applicable generating resources must be able to ride-through system disturbances. Failure to ride-through has been documented in multiple NERC reports leading to exacerbated system conditions, resulting in the electrical disconnecting of additional generation and widespread outages.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Similar requirements in PRC-024-3 are identified as Medium but are based on equipment protection setting documentation rather than actual, recorded performance during a grid disturbance. Therefore, this VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner or Transmission Owner failed to demonstrate the capability of each applicable facility to adhere to performance requirements during voltage excursions, as specified in Requirement R2.~~N/A~~	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable facility adhered to performance requirements during voltage excursions~~IBR adhered to performance requirements during each System disturbance~~, as specified in Requirement R2.

VSL Justifications for PRC-029-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R2	
Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

~~VRF Justifications for PRC-029-1, Requirement R3~~	
~~Proposed VRF~~	**~~Lower~~**
~~NERC VRF Discussion~~	~~A VRF of Lower is appropriate that if violated, it would not be expected to adversely affect the electrical state or capability of the Bulk-Power System.~~
~~FERC VRF G1 Discussion~~ ~~Guideline 1- Consistency with Blackout Report~~	~~This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.~~
~~FERC VRF G2 Discussion~~ ~~Guideline 2- Consistency within a Reliability Standard~~	~~The assignment of Lower VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.~~
~~FERC VRF G3 Discussion~~ ~~Guideline 3- Consistency among Reliability Standards~~	~~This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.~~
~~FERC VRF G4 Discussion~~ ~~Guideline 4- Consistency with NERC Definitions of VRFs~~	~~This VRF is in line with the definition of a Lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.~~
~~FERC VRF G5 Discussion~~ ~~Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation~~	~~This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.~~

~~VSLs for PRC-029-1, Requirement R3~~			
Lower	~~Moderate~~	~~High~~	~~Severe~~
N/A	~~N/A~~	~~N/A~~	~~The Generator Owner or Transmission Owner failed to demonstrate each applicable IBR adhered to performance requirements during each transient overvoltage period as specified in Requirement R3.~~

~~VSL Justifications for PRC-029-1, Requirement R3~~	
~~**FERC VSL G1**~~ ~~Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance~~	~~The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.~~
~~**FERC VSL G2**~~ ~~Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties~~ ~~Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent~~ ~~Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language~~	~~The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.~~

~~VSL Justifications for PRC-029-1, Requirement R3~~	
~~FERC VSL G3~~ ~~Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement~~	~~The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.~~
~~FERC VSL G4~~ ~~Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations~~	~~Each VSL is based on a single violation and not cumulative violations.~~

VRF Justifications for PRC-029-1, Requirement R~~3~~4	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of ~~Lower~~ High is appropriate that if violated, it would not be expected to adversely affect the electrical state or capability of the Bulk-Power System.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of ~~Lower~~ High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a ~~Lower~~ High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R~~4~~3			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner or Transmission Owner failed to demonstrate the capability of each applicable facility to Ride-through in accordance with Attachment 2.~~N/A~~	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable facility adhered to Ride-through requirements in accordance with Attachment 2~~IBR adhered to performance requirements during each frequency excursion event, as specified in Requirement R4~~.

VSL Justifications for PRC-029-1, Requirement R3~~4~~	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R~~3~~4	
Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

~~VRF Justifications for PRC-029-1, Requirement R5~~	
~~Proposed VRF~~	**~~Lower~~**
~~NERC VRF Discussion~~	~~A VRF of Lower is appropriate that if violated, it would not be expected to adversely affect the electrical state or capability of the Bulk-Power System.~~
~~FERC VRF G1 Discussion~~ ~~Guideline 1- Consistency with Blackout Report~~	~~This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.~~
~~FERC VRF G2 Discussion~~ ~~Guideline 2- Consistency within a Reliability Standard~~	~~The assignment of Lower VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.~~
~~FERC VRF G3 Discussion~~ ~~Guideline 3- Consistency among Reliability Standards~~	~~This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.~~
~~FERC VRF G4 Discussion~~ ~~Guideline 4- Consistency with NERC Definitions of VRFs~~	~~This VRF is in line with the definition of a Lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.~~
~~FERC VRF G5 Discussion~~ ~~Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation~~	~~This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.~~

~~VSLs for PRC-029-1, Requirement R5~~			
Lower	~~**Moderate**~~	~~**High**~~	~~**Severe**~~
N/A	~~N/A~~	~~N/A~~	~~The Generator Owner or Transmission Owner failed to demonstrate each applicable IBR adhered to performance requirements during each instantaneous positive sequence voltage phase angle change of less than 25 electrical degrees, as specified in Requirement R5.~~

~~VSL Justifications for PRC-029-1, Requirement R5~~	
~~**FERC VSL G1**~~ ~~Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance~~	~~The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.~~
~~**FERC VSL G2**~~ ~~Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties~~ ~~Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent~~ ~~Guideline 2b: Violation Severity~~	~~The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.~~

~~VSL Justifications for PRC-029-1, Requirement R5~~	
~~Level Assignments that Contain Ambiguous Language~~	
~~**FERC VSL G3**~~ ~~Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement~~	~~The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.~~
~~**FERC VSL G4**~~ ~~Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations~~	~~Each VSL is based on a single violation and not cumulative violations.~~

VRF Justifications for PRC-029-1, Requirement R~~4~~6	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate that if violated, it would not be expected to adversely affect the electrical state or capability of the Bulk-Power System.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of Lower VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a Lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R4~~6~~			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), ~~and~~ Reliability Coordinator(s), and Regional Entity more than 30 calendar days but less than or equal to 60 calendar days after the change to the equipment. OR The Generator Owner or Transmission Owner provided a copy to the applicable entities as detailed in R4.2 more than 12 months but less than or equal to 15 months after the effective date of R4.	The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), ~~and~~ Reliability Coordinator(s), and Regional Entity more than 60 calendar days but less than or equal to 90 calendar days after the change to the equipment.	The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s), and Regional Entity more than 90 calendar days but less than or equal to 120 calendar days after the change to the equipment.	The Generator Owner or Transmission Owner failed to document complete information for facilities identified with known hardware ~~evidence of equipment~~ limitations that prevent the facility from meeting voltage Ride-through criteria as detailed in Requirements R1 or R2~~consistent with Requirement R6 and prior to the effective date of PRC-029-1 Requirement R6~~. OR The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), ~~and~~ Reliability Coordinator(s), and Regional Entity more than 120 calendar days after the change to

			the equipment. OR The Generator Owner or Transmission Owner failed to provide a copy to the applicable entities as detailed in R4.2 within 24 months after the effective date of R4.

VSL Justifications for PRC-029-1, Requirement R4~~6~~	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R4~~6~~	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

Standards Announcement

Project 2020-02 Modifications to PRC-024 (Generator Ride-through) | PRC-024-4 and PRC-029-1

Formal Comment Period Open through July 8, 2024

Now Available

A 20-day formal comment period for **Project 2020-02 Modifications to PRC-024 (Generator Ride-through)**, is open through **8 p.m. Eastern, Monday, July 8, 2024.**

The Standards Committee approved waivers to the Standard Processes Manual at their December 2023 meeting. These waivers were sought by NERC Standards staff for reduced formal comment and ballot periods. This will assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 901. *FERC Order 901 was issued under* Docket No. RM22-12-000 *on October 19, 2023.*

The standard drafting team's considerations of the responses received from the previous comment period are reflected in these drafts of the standards and other documents.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps
Additional ballots for the standards and implementation plans, as well as the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **June 28 – July 8, 2024**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Manager of Standards Development, Jamie Calderon (via email) or at 404-960-0568 Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2020-02 Modifications to PRC-024 (Generator Ride-through) observer list" in the Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2020-02 Modifications to PRC-024 (Generator Ride-through) | Draft 2
Comment Period Start Date:	6/18/2024
Comment Period End Date:	7/8/2024
Associated Ballots:	2020-02 Modifications to PRC-024 (Generator Ride-through) Implementation Plan AB 2 OT 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-024-4 AB 2 ST 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-029-1 AB 2 ST

There were 63 sets of responses, including comments from approximately 138 different people from approximately 91 companies representing 7 of the Industry Segments as shown in the table on the following pages.

Questions

1. Provide any comments for the drafting team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO

					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
California ISO	Darcy O'Connell	2	WECC	ISO/RTO Council (IRC) Standards Review Committee	Ali Miremadi	California ISO	2	WECC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Helen Lainis	Independent Electricity System Operator	2	NPCC
					Elizabeth Davis	PJM Interconnection	2	RF
					Charles Yeung	Southwest Power Pool, Inc.	2	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy	6	RF

						Corporation		
Austin Energy	Michael Dillard	5		Austin Energy	Michael Dillard	Austin Energy	5	Texas RE
					Lovita Griffin	Austin Energy	3	Texas RE
					Tony Hua	Austin Energy	4	Texas RE
					Imane Mrini	Austin Energy	6	Texas RE
					Thomas Standifur	Austin Energy	1	Texas RE
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
DTE Energy	Patricia Ireland	4		DTE Energy	Patricia Ireland	DTE Energy - Detroit Edison	4	RF
					Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison Company	5	RF
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Micah Runner	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC

Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Gary Dollins	M and A	3	SERC

						Electric Power Cooperative		
					William Price	M and A Electric Power Cooperative	1	SERC
					Olivia Olson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	SERC
					Heath Henry	NW Electric Power Cooperative, Inc.	3	SERC
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	KAMO Electric Cooperative	1	SERC
					Brett Douglas	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Mark Riley	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Chuck Booth	Associated Electric Cooperative, Inc.	5	SERC
					Jarrod Murdaugh	Sho-Me Power Electric Cooperative	3	SERC

1. Provide any comments for the drafting team to consider, if desired.

Thomas Foltz - AEP - 5	
Answer	
Document Name	

Comment

The R1, R2, and R3 design requirement is problematic because of at least two major issues: dynamic modeling deficiencies and lack of standardized test procedures. IBR dynamic modeling is well proven to be deficient in representing performance of equipment in the field, particularly disturbance ride-through performance, and even though MOD-026-2 is addressing model verification/validation, it is still only post-interconnection (or post-commissioning). What is needed here is to expand the scope of MOD-026-2 to also encompass pre-interconnection model verification/validation so that “simulations” and “studies” on IBR plant models evaluating the plant designs are performed on verified and validated dynamic models ahead of interconnection. Secondly, without well-defined, standardized test procedures to assess ride-through capability, there is little possibility that simulations and studies on IBR designs will result in uniform across-the-board assurance that IBR equipment and plant designs adequately adhere to the PRC-029 ride-through requirements. Completion of IEEE 2800.2, which is intended to define the necessary testing and verification procedures, and selective consideration and use of its content in PRC-029 is necessary just as 2800 itself has been instrumental in formulating the mandatory ride-through requirements in PRC-029. Without dynamic model verification/validation and well-defined, standardized test procedures, the design components of R1, R2, and R3 will not achieve the desired outcome and will only result in confusion as to what evidence is actually required from GOs and TOs.

Need to indicate in association with R1 third bullet that momentary current blocking is an acceptable means of reacting to non-fault initiated phase jumps greater than 25 degrees.

There is inconsistency throughout the document in instances of both “TO and GO” and “TO or GO”. Please resolve the inconsistencies.

Please clarify what “other evidence” in M1, M2, and M3 would be acceptable to assure compliance. Please also reinsert “shall” in M1, M2, and M3 where it has been removed (to read “Each GO and TO shall have evidence…”). The sentences are not complete without it and measures in other standards (such as PRC-024-4) read that way.

Figures 1 and 2 in Attachment 1 should be better aligned. One has a log scale on the horizontal axis and the other is linear. There is no valid reason for these differences, and we recommend they be consistent in the axes used. The only difference between them should be the slight difference in the lower boundary of the must ride-through zone reflecting the slight difference between Attachment 1 tables 1 and 2.

There needs to be an exemption for system-related causes of ride-through failure. IBRs should be exempt from ride-through requirements in R1 through R3 if tripping or failure to ride through is attributable to any of the following:

1. Sub-synchronous control interaction or ferro-resonance involving series compensation confirmed by the TOP, RC, TP, or PC

2. Unstable behavior of other nearby IBRs or dynamic devices such as FACTS or HVDC confirmed by the TOP, RC, TP, or PC

3. System short circuit levels during contingencies below the level of IBR stable operation confirmed by the TOP, RC, TP, or PC

4. System-level transient or oscillatory instabilities confirmed by the TOP, RC, TP, or PC

R 2.1.3 should be .95 per unit (with a decimal point) rather than 95 per unit.

Likes 0	
Dislikes 0	

Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	
Document Name	
Comment	

1) Editorial suggestions **BOLD** and ***ITALICS*** for the Measures in below

2) In PRC-029, standard as follows:

4.2 Facilities:

4.2.1. BEPS inverter-based resources(2)

(2)For the purpose of this standard, "inverter-based resources" refers to a collection of individual solar photovoltaic (PV), Type 3 and Type 4 wind turbines, battery energy storage system (BESS), or fuel cells that operate as a single plant/resource. ***In case of offshore wind plants connecting via a dedicated VSC-HVDC, the inverter-based resource includes the VSC-HVDC system.***

Question for SDT: ***Should VSC_HVDC be included even if it's not associated with a windplant (ie Transbay Cable HVDC)?***

M1. Is very clunky, below is my attempt to making it read better.

1}· Replace *have* with *has*.

2}· Reword per the following:

o ***Has*** evidence of dynamic simulations, studies, or other evidence to demonstrate the design of each facility will adhere to Ride-through requirements, as specified in Requirement R1. ***As system conditions allow*** each Generator Owner and Transmission Owner ***retain*** evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) recorded to demonstrate that the operation of each facility did adhere to Ride-through requirements, as specified in Requirement R1. If the Generator Owner and Transmission Owner choose to utilize Ride-through exemptions that occur within the "must Ride-through zone" and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner and Transmission Owner also ***retain*** evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate that the facility failed to Ride-through during a phase jump of greater than or equal to 25 electrical degrees, and documentation from their Transmission Planner, Reliability Coordinator, Planning Coordinator, or Transmission Operator that a non-fault initiated switching event occurred.

M2 .

Each Generator Owner and Transmission Owner ***has*** evidence of dynamic simulations, studies, or other evidence to demonstrate the design of each facility will adhere to requirements, as specified in Requirement R2. Each Generator Owner and Transmission Owner also ***retain*** evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data demonstrating that the operation of each facility did adhere to performance requirements, as specified in Requirement R2, during each voltage excursion measured at the high-side of the main power transformer. ***The Generator Owner or Transmission Owner have evidence of receiving such performance requirements, (e.g. email exchange, contract information) if the Transmission Planner, Transmission Operator, Reliability Coordinator, Planning Coordinator has required the Generator Owner or Transmission Owner to follow performance requirements other than those in Requirement R2 (e.g. ramp***

rates, reactive power prioritization).

***3) Question for SDT: What does this mean?* M3 Same comments as M2.**

4) Figure -1 "*Voltage ride-through requirement for AC-connected wind"* on page 20 does not match Attachment 1 Table-1 on page16 for the requirement of <1.2 and > 1.1 minimum ride-through time of 1 second.

5) For PRC-029-1, section B (Requirements and Measures)-

R2- Section 2.2:

In section 2.2, footnote 6: mentions that "*In either case and if required, the magnitude of active power and reactive current shall be as specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator*."

Question/comment for SDT: It has not been mentioned how to identify the magnitude of active power and reactive current, and it seems that Electromagnetic Transient (EMT) studies should be performed to evaluate each IBR and it will result in a significant amount of extra work for PTO to receive, evaluate and perform EMT studies.

Likes 0	
Dislikes 0	
Response	
Ijad Dewan - Ijad Dewan On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Ijad Dewan	
Answer	
Document Name	
Comment	
The Technical Rationale must include reasons for inclusion of Synchronous Condenser to the standard under the applicability section.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	
Dominion Energy supports EEI's additional comments.	
Likes 0	

Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	

FirstEnergy requests the DT consider changing PRC-029-1 Requirement 2 R2.5 from active power to apparent.

Entities may incorporate solar sites that automatically change reactive power to attempt to control voltage similar to FirstEnergy's sites. This change will inevitably cause changes in active power post event, such that meeting this requirement as written could be difficult. Since changes in reactive power are desired for voltage control, the requirement should be changed to allow this response. Using apparent power in the requirement versus active power is one way to achieve this.

Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	
Document Name	
Comment	

- M1: This seems more like a requirement than a measure for meeting the requirement.
- R2, M2, M3 and R4: Duplicative of Mod-026 and MOD-027. Also, seems to be dependent on PRC-028 passing and sites having DDRs installed.
- R2: is not clear. It seems to overlap significantly with VAR-002.
    - Should that be .95 per unit?
- R3: No provisions for exemptions for frequency limitations.
- R4.1 thru 4.2: Are we seeking approval from this large list of entities for an exemption or are we documenting the limitation that prevents from meeting requirement 1? If we have to get approval there is no requirement in this standard that require any of these entities to provide that approval.
    - Recommend limiting who must be notified to just the TP or TP and RC. There needs to be a single point of contact instead multiple entities.

Likes 0	

Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	
Document Name	
Comment	

The draft PRC-029-1 includes expectations in R1, R2, and R3 for entities to demonstrate ride-through adherence (R1 & R3) and performance (R2) through two separate means: 1) dynamics simulations/studies and 2) data from actual system events. These two separate expectations are combined in each requirement but are not clearly delineated within the requirement text. It is only in the measures associated with each requirement that it becomes clear that both expectations exist. This lack of clarity leads to concerns about the auditability of this standard.

The Standard should clearly specify during which timeframes and under what conditions an entity is expected to show compliance using simulations/studies vs. data from actual events. For instance, upon commissioning of a new facility, no event data will be available. Should the CEA expect to see a study completed for a new facility prior to commercial operation? For existing facilities with extensive recorded event data is it still necessary to perform simulations and studies to show compliance? How much event data and how serious must the events be for this to be acceptable?

Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Quebec (HQ) - 1 - NPCC	
Answer	
Document Name	
Comment	

It is imperative that the standard drafting teams for this project as well as the 2021-04 (PRC-002 and PRC-028) and 2023-02 (PRC-030 vs PRC-004) assure a coherent way of addressing the inclusion and exclusion of IBRs in current and upcoming standards.

The following comments are applicable to PRC-029-1

The definition for Inverter Based Resource (IBR) was approved by industry in April under Project 2020-06. We do not agree with inserting the uncapitalized version of IBR into 4.2 Facilities section because it is unbounded and insufficient to identify the Facilities applicable to this Standard, as required in the Rules of Procedure (Appendix 3a, Standard Processes Manual). Furthermore, these definitions are the foundation of several ongoing projects in response to FERC Order 901, where FERC “directs NERC to submit new or modified Reliability Standards that address specific matters pertaining to the impacts of IBRs on the reliable operation of the BPS.”

Chapter A, -Section 4.2.2 What is the “IBR registration criteria”? Please add a footnote to describe it.

Requirement R1: 25degrees, 1.1pu-45s and 1.18pu-2s should be moved to attachment 1 to allow for regional variance.

Requirement -R2-2.1.3 and B-R2-2.2 Can the TP ask for a mix of active/reactive power based on a predetermined ratio (currently only indicated as active OR reactive).

Requirement -R3: No exemption exists for existing equipment limitation to meet frequency and ROCOF ride-through? (like R4 for voltage) One should be added.

Requirement -R3. The 5Hz/s value should be moved to Attachment 2 to allow for a regional variance.

Requirement -R3 The 5Hz/s requirement is already indicated in R1. It should not be repeated.

Requirement -R4: Are the phase shift and V/Hz requirements described in R1 considered as being part of the "voltage ride-through criteria"? (or is it for amplitude only) An exemption should be provided for existing equipment with limitations.

Requirement -R4 and M4 What should be done when the manufacturer does not exist anymore or refuses to collaborate?

Attachment 1: Please explain (footnote) why the ride through requirement for a type-4 wind turbine needs to be different of a PV plant.

The Technical Rationale must include reasons for inclusion of Synchronous Condenser to the standard under the applicability section.

The term "active power" is not defined and appears to be used in conjunction with Real Power. Recommend consistency throughout the standards when using Real Power vs active power, such as MOD-025, BAL-001, and many others.

Recommend the DT reevaluate the implementation period of 6 months. Recommend making implementation period 18 months or greater to account for the need for working with OEMs to implement any setting changes and the need for IBR settings reviews conducted by third parties, as necessary.

Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	

Tri-State has no additional comments for PRC-024-4

Tri-State agrees with MRO NSRF Comments regarding PRC-029-1

Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	

Document Name	
Comment	

- PRC-029-1 Attachment 1
  - Footnotes 10 and bullet 1 seem redundant. Consider consolidation with bullet 4.
  - Footnotes 11, 13 and bullet 5 seem redundant. Consider consolidation.
- Technical Rational for Reliability Standard PRC-029-1
  - Requirement R1, paragraph 5 – missing hyphen in “IEEE 2800-2022”.

Likes 0	
Dislikes 0	
Response	

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	
Document Name	
Comment	

PRC-024: Black Hills Corporation does not have any further comments for this revision for this standard as part of this project.

PRC-029: Black Hills Corporation agrees with the comments identified by the NAGF. They are as follows:

The NAGF believes that PRC-029 should allow for frequency ride through (“FRT”) exemptions similar to its treatment of voltage ride through (“VRT”) exemptions. The justification for allowing VRT exemptions in FERC Order 901 also apply to FRT. We believe the statement in FERC Order 901, paragraph 193 in response to ACP/SEIA’s comment in paragraph 188 does not preclude the standard drafting team from considering FRT exemptions due legacy equipment limitations. Here are a few reasons why:

1. If FERC’s intent was to exclude Frequency Ride Through exemptions while allowing Voltage ride through exemptions, there would be more of a record established to support this differential treatment.

2. FERC responded to ACP/SEIA’s comment on ride-through requirements as if they were only asking about voltage ride through requirements. FERC made no mention of frequency ride through requirements.

3. Similar to FERC’s rational for the consideration of voltage ride through exemptions, there are also older IBR technologies with hardware that would need to be physically replaced to meet frequency ride through requirements as well.

4. NERC and the NERC Standard Drafting Teams have the technical expertise to address complex technical issues such as legacy equipment limitations that FERC does not have.

Applicability Section, 4.2.2 – Recommend removing this section.

Requirement R1: The NAGF notes that R1 only addresses voltage ride through and should be revised to include frequency ride through as well. In addition, R1 should address frequency ride through limitations for legacy IBR facilities.

Measurement M1 – The proposed narrative reads more like requirements than measures; recommend to revise the narrative accordingly. In addition, the NAGF notes that the proposed narrative seems to assume that PRC-028 will be need to be approved/in place for PRC-029 to be a viable standard.

Requirement 2.1.3: The narrative is unclear as to what is expected for this proposed requirement. Request that the narrative be rewritten/restructured to address this issue. In addition, it is unclear which entity will define the preference for active or reactive power. The NAGF *suggests that the Transmission Planner (TP) should have the authority to define this preference. This recommendation also applies to Requirement 2, second bullet and Footnote 6.*

Requirement R2.5: The NAGF recommends that the narrative be revised to state that active power shall be restored when" the voltage at the high-side of the main power transformer returns to the Continuous Operating Region".

Requirement R4: The draft narrative does not clearly specify who is responsible for approving the exemption. The NAGF requests the narrative be revised to address this issue.

Measure M4: Recommend replacing the word "seeking: with "submitting" in the first sentence.

Additionally, Black Hills Corporation reviewed and agrees with EEI's high level concerns for PRC-029, which are:

1. The Standard attempts to redefine the approved definition of IBR by adding VSC-HVDC systems after the IBR definition was approved by the industry.

2. The Standard adds TOs to this Standard solely to address VSC-HVDC systems, yet no technical justification has been provided. Moreover, these systems were not identified in FERC Order No. 901, or this SAR and they were not clearly identified in the Applicability Section of this proposed Reliability Standard.

3. EEI is concerned with the inclusion of requirements that are not clearly defined or set by multiple registered entities (i.e., TP, PC, RC, or TOP). This creates regulatory confusion and places IBR-GOs in a position where they may need to comply with any number of entities without clearly defining who is responsible. (See Requirement R2, subpart 2.1.3; subpart 2.2 (bullet 2); subpart 2.5) Moreover, the identification of multiple entities who could be responsible creates a situation where IBR-GOs will have reporting obligations to multiple entities because no single entity is identified as being responsible. (See requirement R4, subparts 4.2 & 4.2.1; subpart 4.3) We further note that none of the entities identified (i.e., TP, PC, RC, or TOP) are identified within the Applicability section of this proposed Reliability Standard. All of this can create confusion and places considerable burden on the IBR-GOs that needs to be resolved and clarified.

4. Throughout this Reliability Standard there is use of non-glossary terms (i.e., active power vs. Real Power) where glossary terms are available and should be used. While in other cases glossary terms are used but not capitalized. (e.g., reactive power vs. Reactive Power) Greater efforts should be made to use NERC Glossary terms where appropriate and capitalize those terms, as required.

Detailed Concerns

Ride-through Definition Comments: EEI does not support the proposed definition for "Ride-through" as proposed because it is too vague and contains no defined limits, as proposed. We recommend the following changes:

Ride-through: Ability to withstand voltage or frequency Disturbances within defined regulatory limits remaining connected, synchronized with the Transmission System, and continuing to operate**.** *(remove: **in response to System conditions through the time-frame of a System Disturbance.**)*

Applicability Section Comments:

Footnote 1: EEI does not support adding TO that own VSC-HVDC systems because this was not a scope item and is therefore not be included in the scope of this SAR. Moreover, Footnote 1 conflicts with Footnote 2 which defines VSC-HVDC as an IBR, which is again does not in alignment with the approved definition of an IBR.

Footnote 2: EEI does not support Footnote 2 because it expands the definition of IBRs beyond what was recently approved by the industry, noting the expansion of IBRs to include VSC-HVDC. Furthermore, there was no technical justification for adding VSC-HVDC and the SAR did not include adding VSC-HVDC systems to this project. For this reason, we ask that the definition of IBR not be expanded through footnotes and suggest that the DT submit a technical justification for adding VSC-HVDC systems to the applicability section of this Standard, rather than redefining an approved definition in a footnote.

To address our concerns related to Footnotes 1 & 2 we suggest that if VSC-HVDC systems are to be classified as IBRs, then the approved definition should be pulled by NERC and resubmitted with those resources added to the definition and resubmitted to the industry for approval. Alternatively, VSC-HVDC systems could be defined separately, and that definition submitted to the industry for approval. In both cases, a technical justification should be provided to the industry that defines the issues and risks to BPS reliability that VSC-HVDC systems pose

EEI suggests that if the DT believes that certain IBR capabilities as identified under Requirement R2 need (or may need) to be specified then they should identify the entity who should be responsible among the four identified (i.e., TP, PC, RC or TOP); add them to the applicability section of this Reliability Standard; add clear requirements and adjust the reporting obligations for the IBR-GO under Requirement R4.

Requirement R1 & R2 Comments: EEI does not agree with the inclusion of Transmission Owners because they would only have an obligation under this Reliability Standard if VSC-HVDC systems were included. Given we do not support the inclusion of VSC-HVDC systems without a technical justification and modified SAR, we ask that Transmission Owners be removed from Requirement R1.

Measures M1 & M2: EEI is concerned that M1 & M2 contains measures that are overly prescriptive providing little discretion to IBR-GOs in demonstrating their compliance with Requirements R1 and R2 that seem to align more with a Requirement than a Measure. To address our concerns, we offer the following suggested changes to M1 and suggest similar changes be made to M2:

M1. Each Generator Owner (*remove:* ***and Transmission Owner***) **shall** have evidence (*remove:* ***of dynamic simulations, studies, or other evidence to demonstrate the design of each facility will adhere***) **that supports the** Ride-through **capability of each of their facilities**, as specified in Requirement R1. (e.g., simulations, studies, recorded data from disturbance monitoring equipment, etc.) (*remove:* ***Each Generator Owner and Transmission Owner have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) to demonstrate that the operation of each facility did adhere to Ride-through requirements, as specified in Requirement R1.***) If the Generator Owner and Transmission Owner choose to utilize Ride-through exemptions that occur within the “must Ride-through zone” and are caused by non-fault-initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner (*remove:* ***and Transmission Owner***) also have evidence **supporting that exemption. (e.g., studies, simulations or supporting data from disturbance monitoring equipment)** (*remove:* ***of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate that the facility failed to Ride-through during a phase jump of greater than or equal to 25 electrical degrees, and documentation from their Transmission Planner, Reliability Coordinator, Planning Coordinator, or Transmission Operator that a non-fault initiated switching event occurred***).

Requirement R3 & R4: EEI does not support the inclusion of Transmission Owners within Requirements R3 & R4 for the same reasons identified above.

Likes 0	
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

PRC-024-4

No Comments, MH is generally supportive of this proposed standard.

PRC-029-1

Applicability:

The standard switches between BPS (bulk power system) and BES (bulk electric system). For consistency, one term should be used throughout the standard.

R1: bullet # 3:

MH recommends adding a footnote stating that the facility may operate in current block mode if necessary to avoid tripping for non-fault initiated phase jumps greater than 25 degrees.

R2:

MH recommends that the defined terms, Real Power and Reactive Power be used throughout the document instead of active power and reactive power.

R 2.1.3

To SDT: "The voltage is below 95 per unit" should be replaced by "The voltage is below 0.95 per unit"

R 2.1.3 & 2.2

Allowing multiple entities to place potentially conflicting requirements upon an applicable functional entity is unacceptable. Either a single entity be tasked with the obligation, or a hierarchy be provided so that an entity is not placed in a multibed conflicted request situation.

M1, M2, M3, and R4

To SDT: Consistently replace "Each Generator Owner and Transmission Owner" with "Each Generator Owner or Transmission Owner"

R3

This requirement requires that Each Generator Owner or Transmission Owner shall ensure the design and operation are such that each facility adheres to Ride-through requirements during a frequency excursion but does not require any governor response action or capability. The inverter-based resources that "adhere to Ride-through requirements" but are not based on frequency deviation, would comply with the standard requirements, which is not ideal. The TP/PC is expected to specify inverter-based resources performance during abnormal system frequency.

MH recommends:

Each Generator Owner or Transmission Owner shall ensure the design and operation is such that each facility adheres to Ride-through requirements **and response as specified by TP, RC, TOP, or PC** during a frequency excursion.

Implementation plan:

The standard is event-based compliance that requires installing recorded equipment data with higher sampling rates at all applicable legacy IBR Facilities. Therefore, we suggest that the implementation plan for PRC-029 should be aligned with Project 2021-04 (PRC-028-1) for the legacy IBRs. Also, MH recommends that the implementation plan of legacy IBR (a facility that is in service by the effective date of PRC-029-1) be longer than any new interconnected IBR (a facility that is in service after the effective date of PRC-029-1/ PRC-028-1)

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	

Constellation feels that the draft 2 added significant technical requirements that would require OEM collaboration and input on their equipment. Operating at Max capability requires additional analysis from GOs and OEMs to ensure subcomponents in the BOP and WTG side will be able to operate at these limits.

Further, the added language for the high side transformer volts per hz (Hz) settings to exceed 1.1 per unit longer than 45 seconds or exceed 1.18 for longer than 2 seconds will require GO/GOPs to work with the transformer manufacturer to see if these new limits can be met. The volt/hz settings are set to protect the transformer during over excitation conditions and they are above the provided transformer excitation curve from the manufacturer.

Also, the new ride through voltage limits is set so high that the current WTGs will not be able to ride through without tripping due to equipment operating conditions. OEMs are still unsure and not incentivized to collaborate in a timely manner to understand capabilities and limitations.

Finally, Constellation asks the DT to address scheduling and implementation plan. The current plan is not reasonable to implement.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	

Constellation feels that the draft 2 added significant technical requirements that would require OEM collaboration and input on their equipment. Operating at Max capability requires additional analysis from GOs and OEMs to ensure subcomponents in the BOP and WTG side will be able to operate at these limits.

Further, the added language for the high side transformer volts per hz (Hz) settings to exceed 1.1 per unit longer than 45 seconds or exceed 1.18 for longer than 2 seconds will require GO/GOPs to work with the transformer manufacturer to see if these new limits can be met. The volt/hz settings are set to protect the transformer during over excitation conditions and they are above the provided transformer excitation curve from the manufacturer.

Also, the new ride through voltage limits is set so high that the current WTGs will not be able to ride through without tripping due to equipment operating conditions. OEMs are still unsure and not incentivized to collaborate in a timely manner to understand capabilities and limitations.

Finally, Constellation asks the DT to address scheduling and implementation plan. The current plan is not reasonable to implement.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	

Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	
Document Name	
Comment	

AZPS supports the following comments that were submitted by EEI on behalf of its members:

PRC-029-1 Comments:

While EEI appreciates that changes made to address our previous comments for the 1st draft of PRC-029-1, we have some new concerns that need to be addressed.

Our high level concerns are described in our comments below:

1. The Standard attempts to redefine the approved definition of IBR by adding VSC-HVDC systems after the IBR definition was approved by the industry.

2. The Standard adds TOs to this Standard solely to address VSC-HVDC systems, yet no technical justification has been provided. Moreover, these systems were not identified in FERC Order No. 901, or this SAR and they were not clearly identified in the Applicability Section of this proposed Reliability Standard.

3. EEI is concerned with the inclusion of requirements that are not clearly defined or set by multiple registered entities (i.e., TP, PC, RC, or TOP). This creates regulatory confusion and places IBR-GOs in a position where they may need to comply with any number of entities without clearly defining who is responsible. (See Requirement R2, subpart 2.1.3; subpart 2.2 (bullet 2); subpart 2.5) Moreover, the identification of multiple entities who could be responsible creates a situation where IBR-GOs will have reporting obligations to multiple entities because no single entity is identified as being responsible. (See requirement R4, subparts 4.2 & 4.2.1; subpart 4.3) We further note that none of the entities identified (i.e., TP, PC, RC, or TOP) are identified within the Applicability section of this proposed Reliability Standard. All of this can create confusion and places considerable burden on the IBR-GOs that needs to be resolved and clarified.

4. Throughout this Reliability Standard there is use of non-glossary terms (i.e., active power vs. Real Power) where glossary terms are available and should be used. While in other cases glossary terms are used but not capitalized. (e.g., reactive power vs. Reactive Power) Greater efforts should be made to use NERC Glossary terms where appropriate and capitalize those terms, as required.

Detailed Concerns

Ride-through Definition Comments:

EEI does not support the proposed definition for “Ride-through” as proposed because it is too vague and contains no defined limits, as proposed. We recommend the following changes:

Ride-through: Ability to withstand voltage or frequency Disturbances within defined regulatory limits remaining connected, synchronized with the Transmission System, and continuing to operate**. *in response to System conditions through the time-frame of a System Disturbance(remove).***

Applicability Section Comments:

Footnote 1: EEI does not support adding TO that own VSC-HVDC systems because this was not a scope item and is therefore not be included in the scope of this SAR. Moreover, Footnote 1 conflicts with Footnote 2 which defines VSC-HVDC as an IBR, which is again does not in alignment with the approved definition of an IBR.

Footnote 2: EEI does not support Footnote 2 because it expands the definition of IBRs beyond what was recently approved by the industry, noting the expansion of IBRs to include VSC-HVDC. Furthermore, there was no technical justification for adding VSC-HVDC and the SAR did not include adding VSC-HVDC systems to this project. For this reason, we ask that the definition of IBR not be expanded through footnotes and suggest that the DT submit a technical justification for adding VSC-HVDC systems to the applicability section of this Standard, rather than redefining an approved definition in a footnote.

To address our concerns related to Footnotes 1 & 2 we suggest that if VSC-HVDC systems are to be classified as IBRs, then the approved definition should be pulled by NERC and resubmitted with those resources added to the definition and resubmitted to the industry for approval. Alternatively, VSC-HVDC systems could be defined separately, and that definition submitted to the industry for approval. In both cases, a technical justification should be provided to the industry that defines the issues and risks to BPS reliability that VSC-HVDC systems pose

EEI suggests that if the DT believes that certain IBR capabilities as identified under Requirement R2 need (or may need) to be specified then they should identify the entity who should be responsible among the four identified (i.e., TP, PC, RC or TOP); add them to the applicability section of this Reliability Standard; add clear requirements and adjust the reporting obligations for the IBR-GO under Requirement R4.

Requirement R1 & R2 Comments: EEI does not agree with the inclusion of Transmission Owners because they would only have an obligation under this Reliability Standard if VSC-HVDC systems were included. Given we do not support the inclusion of VSC-HVDC systems without a technical justification and modified SAR, we ask that Transmission Owners be removed from Requirement R1.

Measures M1 & M2: EEI is concerned that M1 & M2 contains measures that are overly prescriptive providing little discretion to IBR-GOs in demonstrating their compliance with Requirements R1 and R2 that seem to align more with a Requirement than a Measure. To address our concerns, we offer the following suggested changes to M1 and suggest similar changes be made to M2:

M1. Each Generator Owner shall have evidence that supports the Ride-through capability of each of their facilities, as specified in Requirement R1. (e.g., simulations, studies, recorded data from disturbance monitoring equipment, etc.) If the Generator Owner and Transmission Owner choose to utilize Ride-through exemptions that occur within the “must Ride-through zone” and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner also have evidence supporting that exemption. (e.g., studies, simulations or supporting data from disturbance monitoring equipment)

Requirement R3 & R4: EEI does not support the inclusion of Transmission Owners within Requirements R3 & R4 for the same reasons identified above.

Likes 0	
Dislikes 0	
Response	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	
Document Name	
Comment	
Vistra supports comments made by EEI and Entergy.	
Likes 0	

Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 1

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	
Document Name	

Comment

AECI supports comments provided by the NAGF.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	

Comment

PRC-029:

General Comment: The NAGF believes that PRC-029 should allow for frequency ride through ("FRT") exemptions similar to its treatment of voltage ride through ("VRT") exemptions. The justification for allowing VRT exemptions in FERC Order 901 also apply to FRT. We believe the statement in FERC Order 901, paragraph 193 in response to ACP/SEIA's comment in paragraph 188 does not preclude the standard drafting team from considering FRT *exemptions due legacy equipment limitations. Here are a few reasons why:*

1. If FERC's intent was to exclude Frequency Ride Through exemptions while allowing Voltage ride through exemptions, there would be more of a record established to support this differential treatment.

2. FERC responded to ACP/SEIA's comment on ride-through requirements as if they were only asking about voltage ride through requirements. FERC made no mention of frequency ride through requirements.

3. Similar to FERC's rational for the consideration of voltage ride through exemptions, there are also older IBR technologies with hardware that would need to be physically replaced to meet frequency ride through requirements as well.

4. NERC and the NERC Standard Drafting Teams have the technical expertise to address complex technical issues such as legacy equipment limitations that FERC does not have.

Applicability Section, 4.2.2 – Recommend removing this section.

Requirement R1: The NAGF notes that R1 only addresses voltage ride through and should be revised to include frequency ride through as well. In addition, R1 should address frequency ride through limitations for legacy IBR facilities.

Measurement M1 – The proposed narrative reads more like requirements than measures; recommend to revise the narrative accordingly. In addition, the NAGF notes that the proposed narrative seems to assume that PRC-028 will be need to be approved/in place for PRC-029 to be a viable standard.

Requirement 2.1.3: The narrative is unclear as to what is expected for this proposed requirement. Request that the narrative be rewritten/restructured to address this issue. In addition, it is unclear which entity will define the preference for active or reactive power. The NAGF suggests that the Transmission Planner (TP) should have the authority to define this preference. This recommendation also applies to Requirement 2, second bullet and Footnote 6.

Requirement R2.5: The NAGF recommends that the narrative be revised to state that active power shall be restored when" the voltage at the high-side of the main power transformer returns to the Continuous Operating Region".

Requirement R4: The draft narrative does not clearly specify who is responsible for approving the exemption. The NAGF requests the narrative be revised to address this issue.

Measure M4: Recommend replacing the word "seeking: with "submitting" in the first sentence.

Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	

Response

Karen Demos - NextEra Energy - Florida Power and Light Co. - 1,3,6

Answer	
Document Name	

Comment

Support NEE comments submitted

Likes 0	

Dislikes 0	
Response	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	

Comment

PRC-024-4

No Comments, MRO NSRF is generally supportive of this proposed standard.

PRC-029-1

MRO NSRF recommends that the defined terms, Real Power and Reactive Power be used throughout the document instead of active power and reactive power.

Section 4, footnote 2 – MRO NSRF does not support using a definition for “inverter based resources” that differs from the what is currently being proposed by the standard drafting team responsible for developing the Glossary of Terms definition for this term. There must be alignment between standards prior to any of them being able to move forward.

Measure 1 – This measure is overly prescriptive and does not allow the applicable functional entity sufficient flexibility to demonstrate compliance with Requirement 1. MRO NSRF would recommend the standard drafting team review measures from PRC-024 and align with the approach taken there.

Measure 2 – This measure is overly prescriptive and does not allow the applicable functional entity sufficient flexibility to demonstrate compliance with Requirement 2. MRO NSRF would recommend the standard drafting team review measures from PRC-024 and align with the approach taken there.

Requirement 2.1.3 – This requirement is unclear in its intent. Additionally, allowing multiple entities to place potentially conflicting requirements upon an applicable functional entity is unacceptable. Either a single entity be tasked with the obligation, or a hierarchy be provided so that an entity is not placed in a “catch-22” situation.

Requirement 4 – MRO NSRF Recommends the following modifications to improve clarity:

Each Generator Owner and Transmission Owner identifying a facility that is in-service by the effective date of PRC-029-1, that has known hardware limitations which prevent the facility from meeting voltage Ride-through criteria as detailed in Requirements R1 and R2, and requires an exemption from specific voltage Ride-through criteria shall:

Measure 4 – MRO NSRF recommends changing “seeking” to “documenting” or “submitting”.

Additional comments:

1. The standard switches between BPS (bulk power system) and BES (bulk electric system). For consistency, one term should be used throughout the standard.

2. R1 bullet # 3: MRO NSRF recommends adding a footnote stating that the facility may operate in current block mode if necessary to avoid tripping for non-fault initiated phase jumps greater than 25 degrees

3. M1, M2, M3, and R4: consistent replace “Each Generator Owner and Transmission Owner” with “Each Generator Owner or Transmission Owner”

4. R2, 2.1.3: “The voltage is below 95 per unit” should be replaced by “The voltage is below 0.95 per unit”

Likes 1	Lincoln Electric System, 3, Christensen Sam
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	
Document Name	

Comment

R1 “The instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer and is initiated by a non-fault switching event on the transmission system” - *How is the GO of IBR going to identify the cause of the fault?*

R1 “The Volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.” – *What is the technical rationale behind the 45 second and 2 seconds? This is a very specific scenario as described in the “Technical Rationale”. Requests incorporating language that suggests where it applies.*

M1 *M1 requires multiple data requirements. It is not clear in language. Interpretation is that GO / TO should have evidence that design can meet as well as performance based evidence that it does or does not perform. The amount and time frame to collect evidence is not provided. Is the expectation that this data is only required for a specific event upon the data request?*

The language in R2 requirements does not explicitly state that changes in resource availability (i.e wind or sun) will also affect the active and reactive current or recovery of the IBR.

R2.5 “Each facility shall restore active power output to the pre-disturbance or available level (whichever is lesser) within 1.0 second when the voltage at the high-side of the main power transformer returns from the mandatory operation region or permissive operation region (including operating in current block mode)” *Recommend language updated to “continuous operating region”. IBR units will be limited in capabilities until transient has ended and IBR equipment is no longer sitting at its equipment limiters”*

It is not understood why requirement R1 exists when R2 has all the details. The standard appears to be first written as the test criteria for model validation. Secondly, as a standard to provide data that plant performance matches model. A standard practice guide on the method to demonstrate compliance through dynamic simulations, studies or other evidence is necessary before full adoption of new standard.

Attachment 1

Overall there are concerns with the PRC-029 implementation timeline for any requirement where the OEM has not had time to fully assess the new requirement and utilize the new IEEE2800 testing standard. New standard implementation needs to give GO/TO time to fully assess new requirements; in particular with the multiple disturbance criteria or method OEMs calculate values.

There is no R6

R3/M3 – All Measurement requirements should be confirmed as inclusion into the PRC-028 standard (RoCoF, V/Hz, Phase Angle, etc)

There is no instruction regarding requirement if IBR cannot meet R3 due to Equipment Limitation

R4 Implementation timeline is too short to assess all facilities with additional requirements in PRC-029. There is also not enough time to allow for OEM responses. Recommend tracking an implementation guideline similar to PRC-028 and PRC-030 to meet FERC deadline.

There is no instruction on process to report a new limitation after the full implementation of R4 when a piece of equipment within the IBR may temporarily limit the capability

R4.3 Each Generator Owner and Transmission Owner with a previously submitted request for exemption that replace the equipment causing the limitation shall document and communicate such an equipment change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the equipment change

The language should be clear to state "full replacement". Should not be misinterpreted to include subcomponent replacement.

There is no R5

The Implementation timeline of this standard is the most concerning given the additional requirements generating new review of all facilities and the need to receive additional feedback from OEMs without new testing standard.

The performance data collection requirements will need to align with implementation timeline of PRC-028 at each facility.

A practice guide is highly recommended to demonstrate method and expectation for compliance.

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3

Answer	
Document Name	

Comment

Avista supports the development of a new Reliability Standard to address gaps in Inverter-Based Resource Performance but has concerns with numerous definitions/verbiage.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	
Document Name	

Comment

***R1**: Revise text as follows: "…each facility adheres to voltage Ride-through requirements…"*
WEC also disagrees with M1 and agrees with the comments made by NAGF and EEI.

***R2:** WEC disagrees with text "…shall ensure the design and operation is such…". The requirement must state what TO and GO must do. Otherwise,* *this requirement is open-ended without a measurable statement. The "…shall ensure" has no quantitative meaning and it does not benefit the BES stability.*

2.1: *The proposed "continuous operating region" range conflicts with acceptable continuous operating ranges by Transmission Operators. Many Transmission Operators classify continuous operating range from 0.95 and 1.05 pu, and consider voltage ranges from 0.9 to 0.95 pu and 1.05 to 1.1 pu as abnormal voltage ranges.*

2.1.1: *Continue to deliver the pre-disturbance level of active power or available active power, whichever is less.* ***Please explain and list what entity must do to ensure this requirement is met.***

2.1.2: *Continue to deliver reactive power up to its reactive power limit and according to its controller settings.* ***Please explain and list what entity must do to ensure this requirement is met.***

2.1.3: *What document governs a TP, PC, RC or TO to specify active/reactive power prioritization.*

2.3: *Term "current block mode" may not be understood and its meaning could be misinterpreted. Does it mean mandatory cessation? Please explain and at least define it in footnotes. Assuming this means momentary cessation, it looks like this requirement will allow momentary cessation if necessary to avoid tripping, OR, per 2.3.1 entity can enter current cessation for 5 cycles. It seems the statement contradicts itself.*

2.5: *WEC owns and operates multiple IBR sites and it is in our experience that the limitation to the one second requirement will come from the power plant controller. The ramp rate capabilities of the power plant controllers are far slower than inverter ramp rates and are typically in minutes range. WEC also had an instance where the power plant controller ramp rate increase was denied by the Transmission Operator/Planner. Applying one second requirement will simply be impractical and most entities will take equipment limitation exception that will not benefit the BES.* ***Unless stated in quantitative way (what and when) the requirement R2 provides no benefit to BES.***

M2: *The current version of M2 calls for dynamic simulations, studies, or other evidence* ***plus*** *having ACTUAL disturbance monitoring data proving the Requirement was met. The dynamic simulations/studies can be performed by third-party engineering contractors specializing in these activities to prove each site meets the first part. However, two questions must be addressed regarding actual data: (1) "How" actual data is acquired if SER, DDR and/or Fault Recording does not become mandated. NAGF made a similar point in their response.*
(2) "When" actual data must be submitted as evidence if we as GOs are not specifically asked for it by some other entity. Without some mandate for data, we as GOs are not going to know when every voltage disturbance that would have (should have) triggered a ride-through has occurred on the transmission system.

Attachment 1: *Are items 1 thru 10 requirements or they are notes supplementing Tables 1 and 2? Please define.*
More description needs to be provided on how to apply items 8, 9, and 10.

Attachment 2: *Are items 1 thru 5 requirements or they are notes supplementing Table 3? Please define.*
More description needs to be provided on how to apply item 5.

Likes 0	
Dislikes 0	

Response

Russell Ferrell - Luminant - Luminant Energy - 6

Answer	
Document Name	

Comment

. I support EEI's and Entergy's comments	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	
Document Name	
Comment	
For the applicability section, suggest adding "that owns equipment as identified in section 4.2" after "generator owner" similarly to the proposed PRC-030-1	
Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	
Document Name	
Comment	

none.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	
Document Name	
Comment	
See comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Patricia Ireland - DTE Energy - 4, Group Name DTE Energy	
Answer	
Document Name	
Comment	
No comments at this time	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	
Document Name	
Comment	
Ameren agrees with and supports EEI's comments.	

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	

Comment

PRC-024-4:

· We support creation of new standard PRC-029 to address IBR specific ride through issues, as both the different natures of synchronous and inverter-based generation and several recent events exhibiting significant IBR ride-through deficiencies and failures the causes of which are not relevant to synchronous generators. The approach to address IBR issues should be different to that of PRC-024 because there are too many other factors and causes of IBR ride-through failure not directly related to voltage and frequency protection settings that may and have caused ride-through deficiencies and failures.

· PRC-028 was voted out due to issues around definition of IBR criteria and implementation plan. Separate PRC-029 would allow PRC-024 to pass through the ballot process without many issues.

PRC-029-1:

· Support inclusion of Ride through requirement in the TERM section, which will get included into NERC Glossary of Terms.

· In all the requirements **IBR** is replaced with **Facility**, except the requirement R2.2 as **IBR**. In attachment 1 it is mentioned as **inverter-based resource facility.** That is not consistent.

Likes 0	
Dislikes 0	

Response

Michael Dillard - Austin Energy - 5, Group Name Austin Energy

Answer	
Document Name	

Comment

Austin Energy supports comments posted by NAGF:

PRC-029:

General Comment: The NAGF believes that PRC-029 should allow for frequency ride through ("FRT") exemptions similar to its treatment of voltage ride through ("VRT") exemptions. The justification for allowing VRT exemptions in FERC Order 901 also apply to FRT. We believe the statement in FERC Order 901, paragraph 193 in response to ACP/SEIA's comment in paragraph 188 does not preclude the standard drafting team from considering FRT *exemptions due legacy equipment limitations. Here are a few reasons why:*

*1.	If FERC's intent was to exclude Frequency Ride Through exemptions while allowing Voltage ride through exemptions, there would be more of a record established to support this differential treatment.*

*2.	FERC responded to ACP/SEIA's comment on ride-through requirements as if they were only asking about voltage ride through requirements. FERC made no mention of frequency ride through requirements.*

*3.	Similar to FERC's rational for the consideration of voltage ride through exemptions, there are also older IBR technologies with hardware that would need to be physically replaced to meet frequency ride through requirements as well.*

*4.	NERC and the NERC Standard Drafting Teams have the technical expertise to address complex technical issues such as legacy equipment limitations that FERC does not have.*

Applicability Section, 4.2.2 – Recommend removing this section.

Requirement R1: The NAGF notes that R1 only addresses voltage ride through and should be revised to include frequency ride through as well. In addition, R1 should address frequency ride through limitations for legacy IBR facilities.

Measurement M1 – The proposed narrative reads more like requirements than measures; recommend to revise the narrative accordingly. In addition, the NAGF notes that the proposed narrative seems to assume that PRC-028 will be need to be approved/in place for PRC-029 to be a viable standard.

Requirement 2.1.3: The narrative is unclear as to what is expected for this proposed requirement. Request that the narrative be rewritten/restructured to address this issue. In addition, it is unclear which entity will define the preference for active or reactive power. The NAGF suggests that the Transmission Planner (TP) should have the authority to define this preference. This recommendation also applies to Requirement 2, second bullet and Footnote 6.

Requirement R2.5: The NAGF recommends that the narrative be revised to state that active power shall be restored when" the voltage at the high-side of the main power transformer returns to the Continuous Operating Region".

Requirement R4: The draft narrative does not clearly specify who is responsible for approving the exemption. The NAGF requests the narrative be revised to address this issue.

Measure M4: Recommend replacing the word "seeking: with "submitting" in the first sentence.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	
Document Name	

Comment

WECC suggests the DT should ensure that the labeling on the Project page of the Standard is accurate in terms of what is being considered. The "redline" version is not a true redline from PRC-024-3 it is a redline from a failed version of PRC-024-4 with the language that was voted down shown as "approved" (i.e., text appearing as not being changed.) This could be misleading. There is no mention of Attachment 2A or Attachment 2C in any of the Requirements. It is noted that there is a reference to Attachment 2B in the Quebec variance. Consider changing Requirement R2 language to reference Attachment 2A and incorporate current Attachment 2A language into Attachment 2. And incorporate Attachment 2C language into Attachment 2B. That provides clarity with a minimal change in Requirement R2 language. In theory, this is a set it and forget it Standard unless something changes. The data retention should reflect that condition and not be limited. GOs and TOs will have to be able to demonstrate settings when requested and can not simply say "the settings were done 6 years ago so no evidence is retained". There have been cases where a GO has indicated retrieval of settings required a third party because the GO did not have documentation. Absence of a failure (i.e., unit trip that would need to be reviewed to see if voltage/frequency was the root cause and if the associated relay responded within the "no-trip" zone) is not necessarily a successful reliability indicator and would require quite a bit of data to demonstrate reliable operation resulting in compliance.

Overall for PRC-024-4 WECC is supportive of the efforts and end results.

PRC-029-1

It is unclear why lower cased "facility" is used. In Footnote 2 "facility" is not used but "plant/resource" is used. In the Technical Rationale "plant/facility" is used. Please provide consistency in language within the Standard, the Requirements, and Technical Rationale.

Facilities Section 4.2 is extremely unclear in that it simply says "IBR Registration Criteria" for 4.2.2. Additionally, Footnote 2 does not consider any hybrid resource types (or Facility types or plant types).

R1 indicates "design and operation" which is a valid approach but "design" can be assessed reviewing settings (and simulations, etc.) but "operation" can only be assessed through a review of time periods where applicable voltage (or frequency) demonstrates a change that calls for operation per the Tables. The VSL for R1 is written in a manner that requires that level of assessment (e.g., entities would have to find a point in time where .89 Voltage existed and show they exceeded the minimum Ride-through time.) The VSL is written where a design issue is a lower VSL but the wrong setting would indicate that the operation could not adhere to Attachment 1. Measurement M1 mentions SER/FR/DDR which are covered in PRC-028-1 (Project 2021-04). Are those enough to demonstrate operation to Attachment 1 under the criteria set in the Tables? With PRC-028-1 setting data retention levels so short, the evidence suggested by Measurement M1 will require retention per Evidence Retention requirements in PRC-029-1 to be able to clearly demonstrate compliance.

If using capitalized "Transmission System" in the definition of "Ride-through" use it capitalized in Requirement 1 bullet 3. PRC-024 had MPT and GSU used and "defined". Consistency in use here in PRC-029 (with appropriate changes) to correlate with PRC-024 is appropriate but should be footnoted in Requirement R1 bullets 3 and 4 first prior to being called out in Requirement R2.1.

Measurement M1 is expansive and some of the details should be in the Technical Rationale rather than in a measure. As is, appears to be not consistent and should, at a minimum, include the word "shall" where needed as others Standards (including PRC-024) are written in this manner (e.g.",….shall have evidence…"). M1 does not mention bullet 2.

Requirement 2 will require a voltage excursion to demonstrate operation adhering to Attachment 1. What criteria constitutes a "voltage excursion"? Requirement 2.1- Consider adding a comma after "region" to be consistent with similar language in other parts of Requirement R2.

Requirement 2.1.1 The phrase "or available active power, whichever is less" appears to be supportive of the footnote regarding a frequency excursion but what if the "available active power" is lower than the pre-disturbance level of active power. "Less" could be zero output as the voltage at the MPT high-side could remain within the continuous operation range with the IBR disconnected.

Requirement 2.1.3 Please verify if that should be ".95" per unit versus "95" per unit. Since this Requirement is within the Operations Horizon timeline, the reference to Transmission Planner and Planning Coordinator should be dropped. Furthermore, it is not clear what a GO would operate to if given conflicting orders by the RC and TOP. Consider limiting the "preference" to the TOP who is to set the system voltage expectations per VAR-001.

Requirement 2.2.- Consider "sub Part" formatting used in other Requirements versus bullets for consistency. Since this Requirement is within the Operations Horizon timeline, the reference to Transmission Planner and Planning Coordinator should be dropped. Furthermore, it is not clear what a GO would operate to if given conflicting orders by the RC and TOP. Consider limiting the "requirement" to the TOP who is to set the system voltage expectations per VAR-001. In this bullet the language says "each IBR" versus "each facility" as called out in other parts of Requirement R2. Is that correct?

Requirement R4 is a grandfathering clause and assumes each unit after the effective date will meet Requirements 1, 2, and 3. There should not be any additional implementation timeline built into a Requirement language as this Standard will take time to be approved and there is a proposed 6 month

Implementation Plan. If there is a hardware limitation, it should be known Day 1 of the effective date of Standard and gathering of the limited information should have already been don ein the 6 months leading to the effective date. There is no requirement for an entity to replace the hardware limitation. The entire Requirement will result in documentation with no expectation of mitigation. What data does the DT have to support this exemption language? At a minimum, notification of an issue needs to be provided to the TOP and RC. Suggest a Corrective Action Plan with definitive time requirements to mitigate the issue (or explain why it can not be mitigated) be instituted here.

Footnote 9 may not be necessary as non-US Jurisdictional applicable government authorities have mechanisms in place to implement any Standard.

Within Requirement R4.1- 4.1.1- Call out specifics for consistency. Leaving as "other" invites inconsistency. Use "Ride-through" as that is a proposed defined term (versus "ride-through") in 4.1.2. Be consistent in using "hardware" or "equipment" to avoid confusion throughout Requirement R4. Suggest removing the phrase "or that the limitation cannot be removed by software updates or setting changes" as this is limited to a hardware limitation exemption. Requirement R4.1.5 is ambiguous and clarity should be provided. Requirement 4.2 It is not clear why the Planning Coordinator and Transmission Planner is included here. Model data demonstrating the limitation should be provided through another mechanism. Including the Regional Entity here is not needed or recommended as Regional Entities are NOT subject to Standards. If the DT wants to include providing information to the Regional Entity place it in "Additional Compliance" section (similar to FAC-003) and recognize it as a data submittal. Recommend removal of Regional Entity from the Requirement language.

Measure M4 does not support Requirement R4 with regards to notification timeline in Requirement R4.3, sentence regarding submission of information in 4.1 should not be limited to the Regional Entity (alternatively that sentence could be removed as Regional Entity is covered in next sentence), and there is no information regarding the response timeline in 4.2.1. Furthermore, "experience from an actual event" indicates that the GO/TO could not adhere to the design and operation criteria set—equating to a possible noncompliance. If there is a hardware (or "equipment" depending on where consistency efforts lead) limitation that should be known in the design phase and addressed at that point

There is no corresponding frequency "hardware" limitation language if a facility can not adhere to Attachment 2.

Evidence Retention Section- Requirement R4 has no obligatory requirement to mitigate the hardware(equipment) limitation. As such, entities should be obligated to maintain information demonstrating compliance until the issues are mitigated. There should be language within the Requirement to correct the issue within a certain timeframe. As is, data demonstrating compliance for R4 would not be retained after 5 years and the entity would be held to performing per R1, R2, and R3 in subsequent compliance monitoring efforts unless tracking (and verification of compliance to R4) existed.

Attachment 1- Consider lowercasing "Through" in Table titles as it is part of the proposed defined single word "Ride-through". Consider lowercasing "Continuous Operating Region" as it is not a defined term nor is it capitalized in the Requirement language. Table 1 cannot have "1.1" and "1.10" be in the Mandatory Operation Region and Continuous Operation Region at the same time (e.g., the mathematical operator shows inclusion.) "1.1" should be shown a "1.10" for consistency. Footnote 10 is unclear as Type 3 and Type 4 wind turbines are IBRs and the use of "directly" in the footnote could leave some entities with Type 3 and Type 4 wind turbines to use Table 2. Simply say it is for Type 3 and Type 4 and leave the AC-Connected and directly connected verbiage out to avoid confusion. Note- Anytime a DT says it is clear the issue gets pushed into the compliance environment where suddenly no clarity exists. IBR is a definitive example of clear technical understanding but extremely unclear understanding when applying a compliance lens.

"Voltage Source Converter High Voltage Direct Current" is not defined nor explained. There are inconsistencies in how "Voltage Source Converter High Voltage Direct Current" is displayed—Footnote 1 is lower cased "v" and contains a hyphen after "High"; Bullet 3 does not have a hyphen in "VSC HVDC but bullet 2, Footnote 1, and Footnote 2 does.

Need to be consistent with the depiction of the Figures (in Attachment 2) in terms of what the boundary line depicts (inclusion or exclusion within the "Regions") as entities have struggled in the past versions of PRC-024 (and others). Figure 1 does not depict the 1.1 Voltage point and therefore appears to not support the Table (consider moving the 1.05 down to the boundary between the "1800 second" section and "no time requirement" section depiction while adding 1.1 to the upper boundary of the "1800 second" section.

Figure 2 does not reflect 1.05 Voltage point so the "1800 second" section appears to not be depicted appropriately. Consider adding the 1.05 Voltage point to the y-axis and redraw boundaries for "1800 second" section and "no time requirement" section. 1.05 should be the upper boundary of the "no time requirement" section. To provide consistency and clarity, Table 2 X-axis values should reflect the table values as Figure 1 reflected those (for Table 1) (i.e., show .32 and 1.2).

Since this is an Operating Horizon based Standard why would Bullet 5 depend upon the PC or TP? Bullet 5 and Bullet 6 do not use the same language (use of hyphens, use of neutral, use of ground). Is the intent of Bullet 10 to supersede Bullet 8 (i.e., does not matter is the time associated with the 4 deviations is below the time associated with the voltage?)

Attachment 2- Consider lowercasing "Through" in Table titles as it is part of the proposed defined single word "Ride-through". Table 3 should reflect consistency in the System Frequency column. The frequency slot between 58.5 and 58.8 is not covered (suspect the 6th row needs adjustment as it is referencing the same frequency point—58.8). Additionally, it appears that there may be inconsistency in mathematical operators inclusion or exclusion of certain ranges. DT needs to confirm where 58.8 resides in terms of allowed time. Consider the Table below with bolded changes. For consistency with Voltage tables "N/A" versus "may trip" is suggested and for consistency the DT may consider a footnote as Tables 1 and 2 did in Attachment 1 regarding voltage.

System Frequency (Hz)

Minimum Ride-Through Time (sec)

≥64

N/A

< 64 and ≥61.8

6

< 61.8 and ≥ 61.5

299

< 61.5 and > 61.2

660

≤ 61.2 and **>** 58.8

Continuous

≤ 58.8 and **≥ 58.5**

660

< 58.5 and ≥ 57

299

< 57.0 and ≥ 56

6

< 56

N/A

PRC-024 had "MPT" and "GSU" used and "defined". Consistency in use here in PRC-029 (with appropriate changes) to correlate with PRC-024 is appropriate.

VSLs- Requirement R1--DT should consider a different method to assign levels. While the Requirement language may say "each" perhaps a consideration for the VSL should be fleet-based. As written, the DT has created a "zero" tolerance Requirement. If the design is wrong the operation would be incorrect. Proving that should not take an event to demonstrate (as the compliance argument this will set up is that "there has not been a period where operation would have occurred”).

Requirement R2 and Requirement R3- Essentially same comments as VSLs for Requirement R1

Requirement R4- The notification timeframe appears to be initially set at 30 calendar days for all the VSLs (with adjustments considering the 30 calendar day foundation) but the Requirement R4 language indicates a foundation of “90 days” (also an issue noted in Measurement M4). With the timeframes associated

Implementation Plan—The last sentence regarding Requirement R4 needs to be struck or incorporated within the Requirement language. Requirement R4 says “hardware limitations” and does not specify the “coordinated protection and control settings”. To be clearer the DT should consider changing Requirement R4 language to “inability to modify coordinated protection and control functions”. There is a gap between the language regarding provision of a “copy to applicable entities” in the Lower VSL and what is in the Severe VSL. Effectively the Severe VSL covers 15 month plus 1 day to beyond 24 months. Is that the intent of the DT?

Likes 0	
Dislikes 0	

Response

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	
Document Name	

Comment

Response from ITC Holdings:

“IBR Registration Criteria” is not an applicable Facility.

The applicabilities of PRC-028, PRC-029, and PRC-030 need to be aligned. E.g. A TO that owns the VSC-HVDC connection for offshore wind is subject to PRC-029 but not PRC-028 or PRC-030.

R1 has no value as a standalone requirement and should be incorporated into R2. In other words, you can’t violate R1 without also violating R2, so eliminate R1 or incorporate its subtle value into R2.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment

Minnesota Power supports EEI's comments.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE has the following comments on the PRC-024-4 draft:

- Requirements R1, R2, and R4 use the term 'Facility' when referencing synchronous generator, type 1 or type 2 wind resource, or synchronous condenser. Requirement R3, however, uses a description of the Facility. Texas RE recommends using the term Facility to be consistent with the other requirements. Texas RE recommends the following revision (in bold):

R3. Each Generator Owner and Transmission Owner shall document each known regulatory or equipment limitation that prevents **an** its **synchronous generator, type 1 or type 2 wind resource, or synchronous condenser Facility**, with applicable frequency or voltage protection from meeting the protection setting criteria in Requirements R1 or R2, including (but not limited to) study results, **technical incapability identified after** experience from an actual event, or manufacturer's advice.

'Technical incapability identified after' language is added to clarify that the Facility Owner must conduct detailed analysis to ensure that the Facility is technically incapable of providing the required system support and the specific technical limitations should be documented.

- Please update footnote 4 (Requirement 2.1) on page 5 of 22 (clean version) - changes in bold font:

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 synchronous generator(s), type 1 or type 2 wind resource(s), or synchronous condenser(s); or (ii) provide signals **to same** to trip **the same Facilities**.

- In Requirement R4, Texas RE recommends that each Generator Owner and Transmission Owner shall provide its applicable protection settings to Planning Coordinator *and* Transmission Planner. The applicable data should be provided to both the Planning Coordinator and Transmission Planner so the study model(s) used by Planning Coordinator and Transmission Planner can be updated concurrently. Texas RE recommends the following revision (in bold):

R4. Each Generator Owner and Transmission Owner shall provide its applicable protection settings associated with Requirements R1 and R2 to the Planning Coordinator **or and** Transmission Planner that models the associated Facility 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 settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of protection setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

It is important that the applicable data is provided to the Planning Coordinator and Transmission Planner so that the study model(s) used by PC and TP can be updated concurrently.

- Technical Rationale document - Texas RE recommends the Facilities section include the Frequency and Voltage Protection Settings for Type 1 and Type 2 Wind Resources in addition to the Synchronous Generators and Synchronous Condensers in the title document since they were added to section A 4.2.1.4 of the standard. Texas RE recommends the following revision (in bold):

Facilities (4.2)

Applicability Facilities subparts in Section 4.1**2**.1 were modified to restrict PRC-024-4 to synchronous generators **and Type 1 and Type 2 Wind Resources**. Section 4.2.2 was added as new subparts to identify which synchronous condensers and equipment.

PRC-029-1 Comments

- Ride-through definition: Ride-through capability is the ability of the resource to continuously deliver power during a disturbance event. It appears the phrase ‘continuing to operate’ used in the Ride-through definition is intended to state that the Facility needs to deliver power in response to system conditions. Texas RE recommends the following revision (in bold):

Ride-through: Remaining connected, synchronized with the Transmission System, and continuing to operate **by delivering power** in response to System conditions through the time-frame of a System Disturbance.

Applicability Section 4.2.1: Footnote 2 refers to ‘offshore wind plants connecting via dedicated VSC-HVDC”. Texas RE recommends revising this footnote to include offshore and on-land VSC-HVDC. Texas RE recommends the following revision (in bold):

For the purpose of this standard, “inverter-based resources” refers to a collection of individual solar photovoltaic (PV), Type 3 and Type 4 wind turbines, battery energy storage system (BESS), or fuel cells that operate as a single plant/resource. In case of **offshore any** wind plants connecting via a dedicated VSC-HVDC, the inverter-based resource includes the VSC-HVDC system.

- Applicability Section 4.2.2: Texas RE recommends revising the verbiage to “**Resource which meets** IBR Registration Criteria”.

- Requirement R1: Texas RE recommends clarifying the first bullet to state that the facility is electrically disconnected in order to clear a fault within its protection zone as designed. Texas RE recommends the following revision (in bold):

The facility needed to electrically disconnect in order to clear a fault **within its zone of protection as designed**;

- Measures: Texas RE noticed the Measures for IBRs in PRC-029-1 are more burdensome than the Measures for synchronous generators in PRC-024-4. Though Measures are not enforceable, they are instructive in which activities could be used to demonstrate compliance with a Requirement. For synchronous generators in PRC-024-4, the Measures indicate that a Generator Owner or Transmission Owner can demonstrate compliance by providing a settings sheet or supporting calculations, or the synchronous generator can instead rely on dynamic simulation studies. In contrast, the Measures in PRC-029-1 indicate that the IBR shall have dynamic simulations, studies, or other evidence to demonstrate the design of each Facility, and the Measures also indicate that the IBR shall have evidence of actual disturbance monitoring to demonstrate performance of the Facility in actual historical Ride-through events. These Measures appear to be more burdensome for IBRs than for synchronous generators and also appear to suggest obligations exist beyond what is stated in the enforceable Requirement text.

- Measures: Since the measures are not enforceable, Texas RE encourages the SDT to consider removing shall statements from the measures. Texas RE recommends using similar verbiage to the measures in the CIP standards, which say “Examples of evidence may include, but are not limited to…”

- Measure M1: The first sentence in Measure M1 shows the word “shall” removed, but nothing was put in its place. Is that the intent of the SDT?

- Requirement Part R2.1.3: Texas RE recommends revising Requirement Part 2.1.3 from passive to active voice so it is clear that the Generator Owner or Transmission Owner is the entity giving preference. Texas RE recommends the following revision (in bold):

If the facility cannot deliver both active and reactive power due to a current or apparent power limit or reactive power limit, when the applicable voltage is below 95% per unit and still within the continuous operation region, **then the Generator Owner or Transmission Owner shall give preference to active or reactive power as** required by the Transmission Planner, Planning Coordinator Reliability Coordinator, or Transmission Operator.

- Requirement Part 2.5: If a small number of the inverters or turbines trip offline at a facility during a fault while the voltage remains in the mandatory operation region, will that facility be in violation of Requirement R 2.5?

- Requirement R4: Texas RE noticed Requirement R4 does not provide an opportunity for legacy Facilities to identify an equipment limitation after 12 months from the effective date of PRC-029-1. PRC-029-1 R1 provides an exception for IBRs that document equipment limitations in accordance with R4. In PRC-029-1 R4, a Facility that existed before the effective date of PRC-029-1 shall identify and document information supporting identified hardware limitations no later than 12 months from the effective date of PRC-029-1. Is the intention that equipment limitations identified after this 12-month window will not be eligible for the exception in PRC-029-1 R1? For a Facility that identifies an equipment limitation in the 13th month or beyond, does the SDT intend for that IBR to still be able to document the equipment limitation and qualify for the exception in R1, albeit with the obligation to submit a Self-Report for failing to meet the 12-month deadline in R4? Alternatively, does the SDT intend that an IBR that does not identify an equipment limitation within the 12-month window should never be able to qualify for the exception in R1?

- Requirement R4: Texas RE recommends the measures include evidence that the Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and to the Regional Entity the documented information supporting the identified hardware limitation.

- Attachment 1: Figure 1: Voltage Ride-Through Requirements for AC-Connected Wind Facilities graphical representation should be corrected to match Tables 1 and 2. The continuous operating region is between 1.05-0.9 and Continuous Operating Region (1800 seconds) time delay is greater than 1.05-1.1 voltage level. In Figure 1, Texas RE recommends adding 1.1 above 1.05 in the Continuous Operating Region (1800 seconds). In Figure 2, Texas RE recommends replacing 1 with 1.05.

- Attachment 2: Frequency Ride – Through Criteria table 3 should be updated to reflect the correct low frequency levels for 660 seconds time delay.

≤ 58.8 and < 58.8 58.5

- Page 16 onward: The Mandatory Operation Region and Continuous Operation Region phrases should be lowercase to match changes made to rest of the standard.

Texas RE noticed the word “facility” is lowercase throughout (redline shows it replaces IBR, e.g. in R1). If the intent is to be consistent the applicability, Texas RE recommends using the term “applicable facility” to refer back to 4.2 Applicability section.

Likes 0	
Dislikes 0	

Response

John Pearson - ISO New England, Inc. - 2

Answer	
Document Name	

Comment

ISO New England signs onto comments of the Standard Review Committee of the ISO/RTO Council.

Likes 0	

Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	
Document Name	
Comment	

- Bureau of Reclamation (BOR) notes that PRC-024-4 draft 2 is redlined to the draft 1 (clean version). Draft 2 has accepted all of the redlines from Draft 1, yet the ballot for Draft 1 was below the two-thirds majority of the weighted Segment votes requirement for approval per Appendix 3A of NERC's standard process manual V5 dated 11-28-2023.
- Recommend SDT provide a separate comment form for each Standard under development.
- PRC-029-1 is not applicable to BOR.
- BOR recommends an 18-month implementation timeline for both standards.

Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	
Comment	

- AES CE fully supports the SEIA working group and other industry comments on allowing exceptions for frequency ride through.
- AES CE is concerned by the updated language in several Measures reading "Each Generator Owner and Transmission Owner have evidence of actual disturbance monitoring…" and believe that the simulations and studies used to demonstrate compliant design should be sufficient, similar to PRC-024. There will be many plants that do not experience an applicable disturbance before this Standard becomes effective and therefore cannot demonstrate adherence to ride-through requirements as prescribed. We are also concerned about expectations for this Measure as time goes on, are we expected to document and record every applicable disturbance and the asset's performance? Additional clarification is required if the Drafting Team believes that actual disturbance monitoring language should remain in the Measures.
- The required protection is not currently modeled in basic models and will require substantial effort to ensure we can perform as required. AES CE requests that the Implementation Plan be modified to use a phased-in approach for existing sites to allow adequate time to prepare for these performance requirements. We suggest that the Implementation Plan for PRC-029 should align or lag the Implementation Plan for PRC-028.

Likes 0	
Dislikes 0	
Response	
Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	

Document Name	
Comment	
PNM agrees with the comments made by EEI.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	
Document Name	
Comment	
The term “active power” is not defined and appears to be used in conjunction with Real Power. Recommend consistency throughout the standards when using Real Power vs active power, such as MOD-025, BAL-001, and many others. Recommend the DT reevaluate the implementation period of 6 months. Recommend making implementation period 18 months or greater to account for the need for working with OEMs to implement any setting changes and the need for IBR settings reviews conducted by third parties, as necessary.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	

Document Name	
Comment	

OPG supports NPCC Regional Standards Committee's comments.

Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	
Comment	

EEI offers the following Comment to Draft 2 for PRC-024 and PRC-029.

PRC-024-4 Comments:

EEI has no substantive concerns with any of the proposed changes to PRC-024-4 but point out a minor typo in Requirement R2 (below).

R2. Each Generator Owner and Transmission Owner shall set applicable voltage protection in accordance with PRC-024-4 Attachment 2, such that the applicable protection does not cause the Facility to which it is applied **to** trip within the "no trip zone" during a voltage excursion at the high-side of the GSU or MPT, subject to the following exceptions: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

PRC-029-1 Comments:

While EEI appreciates that changes made to address our previous comments for the 1st draft of PRC-029-1, we have some new concerns that need to be addressed.

Our high level concerns are described in our comments below:

1. The Standard attempts to redefine the approved definition of IBR by adding VSC-HVDC systems after the IBR definition was approved by the industry.
2. The Standard adds TOs to this Standard solely to address VSC-HVDC systems, yet no technical justification has been provided. Moreover, these systems were not identified in FERC Order No. 901, or this SAR and they were not clearly identified in the Applicability Section of this proposed Reliability Standard.
3. EEI is concerned with the inclusion of requirements that are not clearly defined or set by multiple registered entities (i.e., TP, PC, RC, or TOP). This creates regulatory confusion and places IBR-GOs in a position where they may need to comply with any number of entities without clearly defining who is responsible. (See Requirement R2, subpart 2.1.3; subpart 2.2 (bullet 2); subpart 2.5) Moreover, the identification of multiple entities who could be responsible creates a situation where IBR-GOs will have reporting obligations to multiple entities because no single entity is identified as being responsible. (See requirement R4, subparts 4.2 & 4.2.1; subpart 4.3) We further note that none of the entities identified (i.e., TP, PC, RC, or TOP) are identified within the Applicability section of this proposed Reliability Standard. All of this can create confusion and places a considerable burden on the IBR-GOs that needs to be resolved and clarified.
4. Throughout this Reliability Standard there is use of non-glossary terms (i.e., active power vs. Real Power) where glossary terms are available and should be used. While in other cases glossary terms are used but not capitalized. (e.g., reactive power vs. Reactive Power) Greater efforts should be made to use NERC Glossary terms where appropriate and capitalize those terms, as required.

Detailed Concerns

Ride-through Definition Comments:

EEI does not support the proposed definition for “Ride-through” as proposed because it is too vague and contains no defined limits, as proposed. We recommend the following changes:

Ride-through: Ability to withstand voltage or frequency Disturbances within defined regulatory limits remaining connected, synchronized with the Transmission System, and continuing to operate**.**

Applicability Section Comments:

Footnote 1: EEI does not support adding TO that own VSC-HVDC systems because this was not a scope item and is therefore not be included in the scope of this SAR. Moreover, Footnote 1 conflicts with Footnote 2 which defines VSC-HVDC as an IBR, which is again does not in alignment with the approved definition of an IBR.

Footnote 2: EEI does not support Footnote 2 because it expands the definition of IBRs beyond what was recently approved by the industry, noting the expansion of IBRs to include VSC-HVDC. Furthermore, there was no technical justification for adding VSC-HVDC and the SAR did not include adding VSC-HVDC systems to this project. For this reason, we ask that the definition of IBR not be expanded through footnotes and suggest that the DT submit a technical justification for adding VSC-HVDC systems to the applicability section of this Standard, rather than redefining an approved definition in a footnote.

To address our concerns related to Footnotes 1 & 2 we suggest that if VSC-HVDC systems are to be classified as IBRs, then the approved definition should be pulled by NERC and resubmitted with those resources added to the definition and resubmitted to the industry for approval. Alternatively, VSC-HVDC systems could be defined separately, and that definition submitted to the industry for approval. In both cases, a technical justification should be provided to the industry that defines the issues and risks to BPS reliability that VSC-HVDC systems pose.

EEI suggests that if the DT believes that certain IBR capabilities as identified under Requirement R2 need (or may need) to be specified then they should identify the entity who should be responsible among the four identified (i.e., TP, PC, RC or TOP); add them to the applicability section of this Reliability Standard; add clear requirements and adjust the reporting obligations for the IBR-GO under Requirement R4.

Requirement R1 & R2 Comments: EEI does not agree with the inclusion of Transmission Owners because they would only have an obligation under this Reliability Standard if VSC-HVDC systems were included. Given we do not support the inclusion of VSC-HVDC systems without a technical justification and modified SAR, we ask that Transmission Owners be removed from Requirement R1.

Additional Requirement R2 Comment: EEI suggests that there should be clearer linkage between Requirement R1 and R2. We are also concerned that R2 only exempts documented equipment limitations but does not also include the exemptions provided within R1. To address these concerns, we offer the following edits to Requirement R2:

R2. Each Generator Owner shall ensure the design and operation **of** the voltage performance **of its IBR Facilities** adheres to the following **conditions** in accordance with Requirement **R1**. [Violation Risk Factor: High] [Time Horizon: Operations Assessment]

EEI also suggests that the “each facility” be replaced with “IBR Facilities” because the use of the uncapitalized version of facility is too broad, making compliance requirement unclear.

Measures M1 & M2: EEI is concerned that M1 & M2 contains measures that are overly prescriptive providing little discretion to IBR-GOs in demonstrating their compliance with Requirements R1 and R2 that seem to align more with a Requirement than a Measure. To address our concerns, we offer the following suggested changes to M1 and suggest similar changes be made to M2:

M1. Each Generator Owner **shall** have evidence **that supports the** Ride-through **capability of each of their facilities**, as specified in Requirement R1. (e.g., simulations, studies, recorded data from disturbance monitoring equipment, etc.) If the Generator Owner choose to utilize Ride-through exemptions that occur within the “must Ride-through zone” and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner **shall** also have evidence **supporting that exemption. (e.g., studies, simulations or supporting data from disturbance**

monitoring equipment)

Requirement R3 & R4: EEI does not support the inclusion of Transmission Owners within Requirements R3 & R4 for the same reasons identified above.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	
Document Name	

Comment

Regarding PRC-024-4, SMUD has no comments and supports the Standard Drafting Team (SDT) in this latest version of the Standard.

Regarding PRC-029-1, SMUD has the following comments:

1) The voters in Project 2020-06, Inverter-based Resource Glossary Terms draft #2, approved the definition of IBR on April 8, 2024, which is different than the definition proposed in Footnote 2 of PRC-029-1. Using the term "inverter-based resources" and defining it with Footnote 2 is inefficient and would create two definitions for the same resource.

The SDT of PRC-029-1 should coordinate with the SDT of Project 2020-06, and NERC staff, to ensure the definition of IBR and new PRC-029-1 are submitted to FERC simultaneously thereby eliminating another ballot for PRC-029-1 to add the NERC Glossary Term for IBR into the standard and eliminate confusion between IBR and "inverter based resources."

2) Requirement R2.2, the term "IBR" should be replaced with "facility" to be consistent with the rest of the Standard. As currently written, Requirement R2.2 states "While voltage at the high-side of the main power transformer is within the mandatory operation region as specified in Attachment 1, each ***IBR*** [emphasis added] shall…"

3) Requirement R2.1.3 should specify only one entity. As currently written, this sub-requirement gives Transmission Planners, Planning Coordinators, Reliability Coordinators, or Transmission Operators the ability to require the facility to deliver active or reactive power. The SDT should make it clear which single entity can set the requirement to avoid any conflicts.

4) Measure 1 and Measure 2 contain the language "Each Generator Owner and Transmission Owner also have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data ***to demonstrating that the operation of each facility did adhere to performance requirements*** [emphasis added]…"

Some facilities may not have sufficient data from actual system disturbances by the time this Standard becomes mandatory and enforceable. The SDT should allow for the use of simulations and studies to demonstrate compliant design, similar to PRC-024, in such cases where the facility does not have evidence of an actual disturbance.

Likes 0	
Dislikes 0	

Response	
Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

Elevate appreciates the opportunity to comment on the draft NERC standards, particularly those pertaining to future IBR NERC Reliability Standards and FERC Order No. 901 directives.

Adoption of, or Alignment with, IEEE 2800-2022

Elevate continues to strongly encourage NERC to reconsider adoption of IEEE 2800-2022. The unwillingness to adopt IEEE 2800-2022 by NERC is leading to entirely duplicative efforts that are not serving any additional value as compared to the work conducted in the IEEE 2800-2022 developments. It does not appear that a holistic approach and strategy is being taken to meet the FERC Order No. 901 directives, which is leading to very low ballot scores, significant rework, and misalignment with industry recommended practices.

The draft NERC PRC-029 is duplicative with IEEE 2800-2022 Clause 7 yet only covers a small fraction of the IBR-specific capability and performance requirements outlined in that clause. Therefore, there is no clear reliability benefit versus the cost of implementation PRC-029 as compared with IEEE 2800-2022 and the recommendations set forth in the NERC disturbance reports and guidelines.

Elevate strongly recommends a single NERC standard that adopts IEEE 2800-2022 in a uniform and consistent manner. NERC can also issue a reliability guideline or implementation guidance that supports industry implementation of the standard. Rather than recreate parts of IEEE 2800-2022 inconsistently over multiple different standards, Elevate recommends a singular standard for BPS-connected IBR capability and performance requirements related to IEEE 2800-2022. Additional NERC standards can be developed where needed in situations where they are not covered directly with IEEE 2800-2022 (e.g., NERC PRC-030).

Concerns with Draft PRC-029

If the draft PRC-029 standard is to be pursued as currently structured, Elevate would like to highlight the following concerns:

Inconsistencies with PRC-029 and IEEE 2800-2022: There are numerous inconsistencies in the draft standard language and attachment 1 and 2 when compared to IEEE 2800-2022. These should be considered and reviewed for clarity and completeness in the standard. The option to cite IEEE 2800-2022 and use the requirements in the IEEE 2800-2022 directly should be allowed over just the use of Attachment 1/2 (i.e. give each GO/TO the ability to use either of these guides to base their performance off on).

IEEE 2800 identifies the following items, but the standard does not support. Clarification/review should occur for each of these items:

IEEE 2800 recognizes FRT requirement limitations, but the standard does not.

IEEE 2800 recognizes exceptions for Negative-sequence voltage exceeding thresholds

IEEE 2800 recognizes Volts/Hz limitations, but the standard does not.

IEEE 2800 recognizes 500kV system voltages are actually operated in the range of 525kV and therefore has equipment rated to 550kV. These 500kV operating conditions should be considered in the standard.

In IEEE 2800 the frequency ride-through criteria defines 10-minute time periods whereas the standard defines them in a 15 minute time period (Table 3 of Attachment 2). This should be clarified and identified.

Attachment 1: Voltage Ride-through criteria has issues that should be corrected. Row 2, voltage (per unit) has an error, the mathematical operand should be “greater than” for the 1.10 value; this entry should read “=< 1.20 and > 1.10”.

Attachment 1: frequency ride-through criteria should be updated to fully match with IEEE 2800. Creating a different FRT ride-through curve without adequate technical justification will continue to challenge the industry.

The SDT should consider allowing for FRT and V/Hz exemptions, similar to what is already in place for VRT exemptions. Legacy equipment limitations apply to FRT, V/Hz, and VRT ride-through requirements, so exemptions should be allowed for both.

The standard should be updated to explicitly state that the voltage ride-through curves are to be interpreted as voltage vs time duration as is stated in IEEE 2800. This is to ensure that there is no incorrect interpretation that these curves are “envelope” curves. This could be done by adding a new note to explicitly call out the voltage vs time duration interpretation of the curves.

Alignment with FERC Directive for IBR Registration: BPS-connected/non-BES IBRs should be applicable to this standard, as it aligns with the FERC order activities and the on-going NERC Registration effort to incorporate the non-registered BPS-connected IBRs that are owned/operated by the new proposed Category 2 GO and GOP entities. Exclusion of these BPS-connected resources would significantly limit the ability to ensure that all BPS-connected IBRs have adequate voltage and frequency ride-through requirements during BPS/BES disturbances.

Alignment with NERC Glossary Definitions for IBRs: Creating a new definition for “inverter-based resources” is not aligned with the on-going IBR standard related work throughout NERC. By creating a new definition, it seems counter-productive to have a unique definition of IBRs and IBR units under the different NERC standards. Having all standards aligned to the new core NERC Glossary definition for IBRs will make all this standard development work, execution of the standards, and compliance activities more efficient for all entities involved.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	
Document Name	

Comment

Thank you for the opportunity to provide comments and for your work on this project. Invenergy provides the below comments for the Drafting Team to consider:

R1: In response to industry comments, the SDT indicated that Requirement R5 from Draft 1 was removed, but it appears the phase-angle jump requirements have simply been reinserted under Requirement R1 in this second draft. As drafted, a facility is expected to ride-through fault-initiated switching events regardless of the magnitude of voltage phase angle change. Consider that positive sequence phase angle change cannot be accurately measured during a fault occurrence and clearance. We propose the assessment of ride-through performance during fault occurrence, clearance, and recovery be based only on the voltage ride-through criteria in Attachment 1 Table 1 and Table 2.

We recommend reverting the “Voltage (per unit)” columns of Table 1 and Table 2 back to their first draft state to remain consistent with Tables 11 and 12 of IEEE 2800.

R2.1.3: The decimal place is missing from “95 per unit.”

R2.2: Consider more clearly defining “maximum capability.” As an alternative, R2.2 could state, “…each IBR shall exchange current, up to the total sum of the nameplate current rating of online IBR units in the plant to provide voltage support…”

R2.3.1: Consider removal of this requirement. The time it should take a facility to restart current exchange following blocking seems irrelevant if the other ride-through performance requirements are being met.

Attachment 1: Note 11 from Attachment 1 should be removed. There are many equipment protection settings that are near instantaneous to protect against current or voltage surges that far exceed the equipment’s maximum rating. A power electronic switch could burn out in a matter of micro-seconds due to such a surge, before any tripping decision could be made if the filtering length must be at least 16.6 milliseconds.

R3: We recommend reverting the “System Frequency (Hz)” columns of Table 3 back to its first draft state to remain consistent with Tables 15 of IEEE 2800.

The Consideration of Comments document seemed to indicate that the drafting team intended to respond to our previous comment regarding the expansion of the frequency ride-through range, but none was provided. The proposed 6-second frequency ride-through capability requirement for the ranges of 61.8Hz to 64Hz and 57Hz to 56Hz does not align with the requirements on the rest of the BES and would expose synchronous generators to dangerous variations in frequency. Can the drafting team cite more specific reasoning or data to support the expansion of the frequency ride-through capability requirement to the range of 64Hz to 56Hz, well beyond the IEEE 2800-2022 standard frequency ride-through requirement and the capabilities of many legacy IBRs?

R4: We recommend the following revision to R4.

R4. Each Generator Owner and Transmission Owner identifying a facility with a signed interconnection agreement by the effective date of PRC-029-1 with known hardware limitations that prevent the facility from meeting ride-through criteria as detailed in Requirements R1, R2, and R3, and requires an exemption from specific ride-through criteria shall:

Exemptions in R4 should be based on the execution of the interconnection agreement rather than the in-service date of the facility. As drafted, facilities with executed interconnection agreements, but not yet in-service by the effective date of the standard may need to make significant equipment modifications and perform interconnection restudies to comply with requirements that did not become effective until after the interconnection agreement was executed.

Regarding the lack of frequency ride-through exemptions, the limited exception language in FERC Order 901 is not supported by any comments or other evidence in the record in the original NOPR proceeding, and therefore we believe this to be an inadvertent omission and unjustified application of Order 901 in the draft language of PRC-029-1. In fact, in the NOPR, FERC proposed to direct NERC “to develop new or modified Reliability Standards that would require Generator Owners and Generator Operators to ensure that their registered IBR facilities ride through system frequency and voltage disturbances **where technologically feasible**.” The drafted frequency ride-through performance requirements are not technologically feasible for many legacy IBRs.

Further, in Order 901, FERC “encourage[s] NERC’s standard drafting team to consider currently effective Reliability Standard PRC-024-3, Requirement R3 as an example for establishing registered IBR technology exemptions.” Requirement R3 of PRC-024-3, and the currently drafted version of PRC-024-4, allows for exemptions from both the frequency and voltage ride-through requirements due to equipment limitations.

Given the lack of a clear evidentiary record on this point, the drafting team should rely on the discretion FERC has always granted NERC when it comes to drafting and implementing practical Reliability Standards. Invenergy recommends Requirement R4 be amended to allow limited exemptions from specific voltage and frequency ride-through criteria for facilities with known hardware limitations that prevent the facility from meeting the ride-through criteria detailed in Requirements R1, R2, and R3.

Finally, Invenergy has concerns regarding the deviation of this project from its original goal of developing a standard that will require ride-through performance from *all* generating resources. As currently drafted, PRC-024-4 imposes fewer ride-through performance responsibilities on synchronous generators while allowing broader exemptions from its requirements than PRC-029-1. This undue discrimination permits scenarios in which both a synchronous generator and an IBR could trip offline due to the same system disturbance and only the IBR would be subject to a potential noncompliance, assuming the synchronous generator did not trip due to its protection system settings.

Implementation Plan: In its Consideration of Comments, the drafting team indicated that the Implementation Plan has been modified such that PRC-029-1 shall become effective on the first day of the first calendar quarter that is 12 months after the effective date of the applicable governmental

authority's order approving PRC-028-1, however the Implementation Plan still lists an implementation timeframe of six months.	
Likes 0	
Dislikes 0	
Response	
Maozhong Gong - GE - GE Wind - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
-In R1, suggest the phase jump measurement to align to 2800 definition i.e.,Sub-cycle-to-cycle -In Attachment 2, frequency ride through table is different with 2800. Suggest to align to 2800, otherwise the OEMs need to design for different specs. -For R4.1, 12 months is not sufficient for documenting the supporting information for hardware limitation. Recommend a 2-year period for the exception documentation.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	
PRC-029 R 2.1.3 should be 0.95 per unit not 95 per unit. Figures 1 and 2 in Attachment 1 of PRC-029 should use the same scale on the horizontal axis, either log or linear. Please clarify point 10 of attachment 1 of PRC-029: "The facility may trip for more than four deviations of the applicable voltage at the high-side of the main power transformer outside of the continuous operation region within any 10 second time period." The Implementation Plan should be extended to 36 months to allow for monitoring equipment to be installed at sites completed before PRC-029 becomes enforceable, to demonstrate performance and compliance with the standard.	
Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 3	
Answer	
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Chance Back - Muscatine Power and Water - 5	
Answer	
Document Name	
Comment	
I support NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
AEPC only has minor concerns with PRC-024-4; however, in our opinion, PRC-029-1 still needs some work before we can recommend approval. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	

Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	
Document Name	
Comment	

It is imperative that the standard drafting teams for this project as well as the 2021-04 (PRC-002 and PRC-028) and 2023-02 (PRC-030 vs PRC-004) assure a coherent way of addressing the inclusion and exclusion of IBRs in current and upcoming standards.

The following comments are applicable to PRC-029-1

The definition for Inverter Based Resource (IBR) was approved by industry in April under Project 2020-06. We do not agree with inserting the uncapitalized version of IBR into 4.2 Facilities section because it is unbounded and insufficient to identify the Facilities applicable to this Standard, as required in the Rules of Procedure (Appendix 3a, Standard Processes Manual). Furthermore, these definitions are the foundation of several ongoing projects in response to FERC Order 901, where FERC “directs NERC to submit new or modified Reliability Standards that address specific matters pertaining to the impacts of IBRs on the reliable operation of the BPS.”

The purpose section of PRC-029-1 refers to Inverter-Based Resources (IBRs) (capitalized, defined term) whereas the facilities section uses the uncapitalized version.

Section 4.2.2: What IBR Registration Criteria are we referring to? Are we referring to the Category 2 GO/GOP facilities that are still awaiting a FERC decision? This section is not consistent with project 2021-04.

For requirements R1 through R4, it is unclear which facilities are being referred to. Suggest rewording to “facilities identified in Section 4.2” or adding a sentence to 4.2 to indicate “For the purpose of this standard, the term “Applicable facilities” refers to the following:”. However, as stated above, it is unclear what facilities are included in the IBR Registration Criteria.

Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	

Duke Energy offers the following Comments for Draft 2 of PRC-024 and PRC-029 - see Duke Energy, EEI and NAGF comments below.

PRC-024-4 Comments

1-Duke Energy recommends the following R2 word omission be rectified:

R2. Each Generator Owner and Transmission Owner shall…which it is applied “to” trip within…

PRC-029-1 Comments

EEI COMMENTS

Duke Energy agrees with and supports EEI filed comments as summarized below - see official EEI filed comments for additional detailed comments and proposed resolution(s):

1-The Standard attempts to redefine the approved definition of IBR by adding VSC-HVDC systems after the IBR definition was approved by the industry. EEI does not support: (a) expansion of the definition of IBRs beyond what was recently approved by the industry, since there is no technical justification for adding VSC-HVDC and, (b) the SAR did not include adding VSC-HVDC systems to this project. For these reasons, we ask that the definition of IBR not be expanded, and that the DT submit a technical justification for adding VSC-HVDC systems to the applicability section of this Standard, rather than redefining an approved definition in a footnote.

2-The Standard adds TOs to this Standard solely to address VSC-HVDC systems although: (a) no technical justification has been provided, and (b) these systems were not identified in FERC Order No. 901, the SAR, or in the Applicability Section of this proposed Reliability Standard.

3-EEI is concerned with the inclusion of requirements that are not clearly defined or set by multiple registered entities (i.e., TP, PC, RC, or TOP). This situation creates: (a) regulatory confusion and places IBR-GOs in a position where they may need to comply with any number of entities without clearly defining who is responsible, (b) IBR-GOs will have reporting obligations to multiple entities because no single entity is identified as being responsible, and (c) none of the entities identified (i.e., TP, PC, RC, or TOP) are identified within the Applicability section of this proposed Reliability Standard. This situation will likely create confusion and places considerable regulatory burden on the IBR-GOs and requires resolution and additional clarification.

4-Throughout this Reliability Standard there is use of: (a) non-glossary terms (i.e., active power vs. Real Power) where glossary terms are available and should be used and (b) glossary terms are used but not capitalized (e.g., reactive power vs. Reactive Power). Greater efforts should be made to use NERC Glossary terms where appropriate and capitalize those terms, as required.

5-Ride-through Definition:

EEI does not support the proposed definition for "Ride-through" as proposed because it is too vague and contains no defined limits, as proposed. We recommend the following changes: Reference EEI filed comments for this item.

6-Applicability Section:

(a) Footnote 1: EEI does not support adding TOs that own VSC-HVDC systems because it was not a scope item and is therefore not included in the scope of this SAR.

(b) Footnote 1 conflicts with Footnote 2 which defines VSC-HVDC as an IBR, which is not in alignment with the approved definition of an IBR.

(c) Footnote 2: EEI does not support Footnote 2 because it expands the definition of IBRs beyond what was recently approved by the industry, noting the expansion of IBRs to include VSC-HVDC.

(d) There was no technical justification for adding VSC-HVDC and the SAR did not include adding VSC-HVDC systems to this project.

For these reasons, we ask that the definition of IBR not be expanded through footnotes and suggest that the DT submit a technical justification for adding VSC-HVDC systems to the applicability section of this Standard, rather than redefining an approved definition in a footnote.

To address our concerns related to Footnotes 1 & 2, we suggest that if VSC-HVDC systems are to be classified as IBRs, then the approved definition should be pulled by NERC and resubmitted with those resources added to the definition and subsequently resubmitted to the industry for approval. Alternatively, VSC-HVDC systems could be defined separately, and that definition submitted to the industry for approval. In both cases, a technical justification should be provided to the industry that defines the issues and risks to BPS reliability that VSC-HVDC systems pose.

EEI suggests that if the DT believes certain IBR capabilities as identified under Requirement R2 need (or may need) to be specified then the DT should identify the entity who should be responsible among the four identified (i.e., TP, PC, RC or TOP); add them to the applicability section of this Reliability Standard; and add clear requirements and adjust the reporting obligations for the IBR-GO under Requirement R4.

7-Requirement R1 & R2:

EEI does not agree with the inclusion of Transmission Owners because they would only have an obligation under this Reliability Standard if VSC-HVDC systems were included. Given we do not support the inclusion of VSC-HVDC systems without a technical justification and modified SAR, we ask Transmission Owners be removed from Requirement R1.

8-Measures M1 & M2:

EEI is concerned that M1 & M2 contains measures that are overly prescriptive and provide little discretion to IBR-GOs in demonstrating their compliance with Requirements R1 and R2. As written, M1 and M2 appear to align more with a Requirement than a Measure (see official EEI filed comments for additional detailed comments and proposed resolution(s)).

9-Requirement R3 & R4: EEI does not support the inclusion of Transmission Owners within Requirements R3 & R4 for the same reasons identified above.

DUKE ENERGY COMMENTS

Additionally, Duke Energy provides the following additional comments:

10-Amend Standard to include GO specific and comprehensive responsibilities and identify functional entity required to approve exemption(s).

11-R3 does not provide specific Measure information in the Requirement – amend; as stated above, this action must provide definitive compliance guidance for GOs.

12-R4: Language does not allow for frequency exemptions (voltage exemptions allowed) – amend Requirement to allow for frequency exemptions.

13-R4.2.1 Amend language to require Regional Entity to respond within X calendar days.

14-R3: Amend language as follows: …“and suggest similar changes be made to M2” and M3.

15-R2.1.3: Requirement is duplicative with VAR-002 Reactive/Voltage support – consider removing.

16-Duke Energy recommends the word “ensure” be removed from all Requirements and specific Requirement language obligations be inserted to identify compliance. Use of the word “ensure” results in global compliance guidance that is not auditable unlike specific compliance Requirement(s).

17-Measurement M1: Consider including a standard Prerequisite Section in Standard that validates design and operation is such that each facility adheres to Ride-through requirements

18-M4/R4.3 – Resolve 30 calendar days vs. 90 calendar days conflict or clarify differences. Also, add “calendar” days to R4.3.

NAGF COMMENTS

Finally, Duke Energy agrees with and supports NAGF filed comments summarized below - see official NAGF filed comments for additional detailed comments and proposed resolution(s):

19-Consider removing Applicability 4.2.2 section, IBR Registration Criteria.

20-R2.5 requires clarity – revise narrative to state that active power shall be restored when ”the voltage at the high-side of the main power transformer returns to the Continuous Operating Region”.

Likes 0	
Dislikes 0	

Response

Michael Goggin - Grid Strategies LLC - 5	
Answer	
Document Name	
Comment	

In the draft of PRC-029, R4 should be modified to allow existing resources with equipment limitations to obtain an exemption from the frequency ride-through requirements in R3, instead of only allowing an exemption from the voltage ride-through requirements in R1 and R2. This is necessary because some existing IBR generators cannot meet the stringent frequency ride-through requirements proposed in R3 without deploying significant hardware modifications or replacement, which goes against the intent of FERC Order 901.

The frequency ride-through requirements are particularly problematic for some existing wind generators. In the Technical Rationale document accompanying the PRC-029 draft, the drafting team notes that some wind generators are more sensitive to frequency deviations, writing that “All IBR resources (except for type 3 wind turbines) interface to the grid through fast switching of power electronics devices. These power electronic devices are much less sensitive to the transmission system frequency excursion than non-hydraulic turbine synchronous resources.”{C}[1] However, the drafting team then incorrectly concludes that “Therefore, IBR should be capable of riding through the increased proposed 6-second frequency ride-through requirement without risk of equipment damage or need for frequency protection to operate.” The Technical Rationale document does not offer any justification for its assumption that Type III wind turbines can meet the frequency ride-through requirements, despite noting that those turbines more directly interface with the grid and thus are more affected by frequency deviations than other IBRs.

In fact, many existing Type III wind turbines cannot meet the frequency ride-through requirements proposed in this draft of PRC-029. Those resources were designed to meet the reliability Standards and interconnection requirements that were in effect when they were placed in service, and were not designed to ride through frequency excursions of the magnitude and duration proposed in the draft Standard. Other types of existing IBR resources were also not designed to meet the proposed frequency ride-through requirements, and may similarly require extensive equipment modification or replacement to comply with R3.

Imposing a retroactive requirement on wind generators is particularly problematic as it is not typically feasible to retrofit existing wind turbines to increase their ability to ride through and withstand mechanical stresses due to frequency changes. In such cases, making existing equipment better able to withstand frequency changes would require full replacement or extensive modification of hardware, which would come at a significant, and sometimes prohibitive, cost. Frequency changes can impose mechanical stresses on highly sensitive elements in the wind turbine’s rotating equipment, including the generator, gearbox, the main shaft, and bearings associated with all of that equipment, and requiring such resources to ride through frequency changes they were not designed to operate through can damage that equipment. Subjecting Type III wind turbines to this damage may lead to increased outages or premature failure of these generators, potentially increasing reliability risks.

The easiest solution is to modify R4 to allow existing resources with equipment limitations toobtain an exemption from the frequency ride-through requirements in R3, which would make PRC-029 consistent with a long precedent of FERC interconnection requirements and NERC Standards only applying prospectively, including PRC-024. Retroactive requirements impose a much greater financial burden on the generator than prospective Standards, and set a bad precedent by unfairly penalizing generators that met all requirements that were in effect at the time they were installed. Retrofit or replacement costs are typically much greater than if the capability were installed at the plant to begin with. In some cases equipment needed for retrofits may not be available, particularly for models that have been discontinued or manufacturers that are no longer in business, potentially requiring the replacement of the entire wind turbine. Moreover, existing IBR generators typically sell their output at a fixed price under a long-term power purchase agreement, and unexpected retrofit or replacement costs cannot typically be recovered once a power purchase agreement has been signed. These unexpected and unrecoverable costs are far more concerning to lenders and other generation project financiers as they were not accounted for during the project’s financing. As a result, retroactive requirements set a bad precedent by introducing regulatory uncertainty that makes future generation investment more uncertain and riskier, and likely more costly by forcing financiers to charge higher risk premiums.

Fortunately, these problems can be fixed by inserting “R3” into the list of permissible exemptions in R4, which would allow existing resources with equipment limitations to obtain an exemption from the frequency ride-through requirements in R3.

In the Technical Rationale document, the drafting team points to FERC’s directive in Order No. 901 to justify not allowing existing resources to obtain an exemption from the frequency ride-through requirements in R3: “FERC Order No. 901 states that this provision would be limited to exempting ‘certain registered IBRs from voltage ride-through performance requirements.’ This is the reason that no similar provisions are included for exemptions for frequency or rate-of-change-of-frequency (ROCOF) ride-through requirements per R3."[2]

However, a contextual reading of Order No. 901 indicates FERC was focused on targeting equipment limitation exemptions at existing generators that would have to physically replace or modify hardware to comply with the Standard, and not focused on limiting such exemptions to voltage ride-through requirements. Paragraph 193 in its entirety, and particularly the first sentence, explain that FERC's intent was exempting existing resources that would have to physically replace or modify hardware: "we agree that a subset of existing registered IBRs –typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements directed herein." As a result, FERC continued by directing that "Any such exemption should be only for voltage ride-through performance for those existing IBRs that are **unable to modify their coordinated protection and control settings to meet the requirements without physical modification of the IBRs' equipment**."[3]

Allowing existing plants to apply for an equipment limitation exemption for the frequency ride-through requirements in R3 is necessary to ensure some existing generators do not have to physically replace or modify hardware. As a result, such an exemption is consistent with FERC's directive and intent in Order No. 901. As documented in the following footnote, there is ample precedent for NERC and standards drafting teams to exercise their technical expertise to craft Standards to align content and requirements with technical realities.[4]

Additional context in Order 901 further demonstrates that FERC intended for NERC to include an exemption for existing IBRs that cannot meet frequency ride-through requirements. At paragraph 190 in Order No. 901, FERC directed NERC to develop Standards that ensure resources "ride through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults." For many existing IBRs that cannot meet the proposed frequency ride-through requirements, tripping is necessary to protect the IBR equipment, similar to when synchronous generation resources use tripping as protection from internal faults. As a result, an exemption from R3 for existing resources is consistent with FERC's intent. Order No. 901 also directed NERC to consider the "PRC-024-3, Requirement R3 as an example for establishing registered IBR technology exemptions," and that exemption applies equally to voltage ride-through and frequency ride-through settings, further suggesting that FERC will allow certain IBRs an exemption from the frequency ride-through requirements.[5] Finally, Order No. 901 notes that in the notice of proposed rulemaking that led to the order, FERC "proposed to direct NERC to develop new or modified Reliability Standards that would require registered IBR facilities to ride through system frequency and voltage disturbances where technologically feasible."[6] FERC then adopted that very proposal,{C}[7] further demonstrating that FERC sought to direct NERC to only require frequency and voltage ride-through where technologically feasible.

It is likely that FERC Order No. 901 did not explicitly direct NERC to include frequency ride-through exemptions because FERC did not anticipate that NERC would adopt such an aggressive frequency ride-through requirement that some existing plants cannot meet. The drafting team even notes at page 7 in the Technical Rationale document that "The proposed 6-second time frame of the frequency ride-through capability requirement is beyond the IEEE 2800 standard frequency ride-through requirement and beyond frequency ride-through requirements for synchronous machines under proposed PRC-024-4." There is nothing in Order No. 901 that suggests that FERC was opposed to existing equipment exemptions for a frequency ride-through standard that was drafted after FERC issued Order No. 901 and is more stringent than FERC anticipated. A much more reasonable interpretation is that the logic FERC provided in paragraph 193 of Order No. 901 also applies to a frequency ride-through requirement that some existing resources cannot meet without physical modification or replacement of equipment. In fact, paragraph 193 makes clear that FERC's language focuses on an exemption from voltage ride-through requirements because "a subset of existing registered IBRs… may be unable to implement the voltage ride though performance requirements directed herein."

At the end of paragraph 193, FERC also explained that an exemption for existing resources would not harm reliability because "The concern that there are existing registered IBRs unable to meet voltage ride through requirements should diminish over time as legacy IBRs are replaced with or upgraded to newer IBR technology that does not require such accommodation." FERC's reasoning in paragraph 193 also applies to an exemption from frequency ride-through requirements, but particularly the conclusion that exempting existing plants does not cause reliability concerns and therefore should be allowed. The NERC drafting team's technical justification document explicitly explains that the frequency ride-through requirement is "to ensure the reliability of future grids with high IBR penetration,"{C}[8] based on concerns about declining inertia due to IBRs replacing synchronous resources. NERC and others have demonstrated that inertia and frequency response will remain more than adequate for the foreseeable future even following disturbances that are several times larger than current credible contingencies, and that higher IBR penetrations can actually significantly improve frequency stabilization following disturbances.[9]

As a result, there is no reliability concern from an exemption for the small number of existing resources that cannot meet the requirements without physical modification or replacement of equipment. Moreover, as FERC notes, these plants will replace that equipment anyway over time as legacy inverters fail or are replaced with more modern equipment for other reasons, and the draft standard requires replacement equipment to comply with the

Standard. Utility-scale inverters installed at solar and battery installations typically come with warranties of 10 years or less,{C}[10] and those inverters are typically replaced at least once during the plant's lifetime. Many existing wind plants are also being repowered with newer turbines, often to allow the project to receive another 10 years of production tax credits after the initial 10 years of credits have been received. As a result, by the time the drafting team's concerns about inertia in a high IBR penetration future might materialize, the vast majority of IBRs that cannot meet the frequency ride-through requirements will have been replaced with new equipment that is not exempt.

Moreover, the drafting team's assumption that frequency deviations will be larger on a future low inertia power system is flawed. IBRs can provide fast frequency response, which stabilizes frequency in the initial seconds following a grid disturbance, before synchronous generators begin to provide their slower primary frequency response.[11] Thus fast frequency response provides a similar service to inertia in helping to arrest the change in frequency before primary frequency response is fully deployed, reducing the need for inertia.[12] Fast frequency response is easily provided by batteries due to their available energy, but can also be provided by curtailed wind or solar resources. Power systems with high IBR penetrations will tend to have some wind or solar curtailment in a significant share of hours. If allowed to do so, solar an battery resources with spare DC capacity behind the inverter can also temporarily exceed their interconnection agreement's AC injection limit to provide fast frequency response.

The replacement of inflexible synchronous resources with more flexible IBRs could also significantly improve primary frequency response, as NERC's modeling has demonstrated.{C}[13] NERC has also documented that only about 30% of synchronous generators provide primary frequency response, and only about 10% provide sustained primary frequency response.[14] Even with less inertia, the fast and accurate frequency response provided by IBRs will keep frequency more tightly controlled than the slow to nonexistent primary frequency response from synchronous generators. The replacement of large synchronous generators with smaller IBRs should also reduce the magnitude of frequency deviations following the loss of generators. If frequency response does begin to emerge as a concern, the more effective solution would be to enforce requirements on synchronous generators that are supposed to provide it but do not. If necessary, operators would alter real-time dispatch, as ERCOT and some island power systems occasionally do today, to ensure that inertia and fast frequency response are adequate to ensure under-frequency load shedding or generator tripping thresholds are not reached. Finally, grid-forming inverters are increasingly being deployed with battery storage and other IBR installations, further increasing the contributions of IBRs to stabilizing frequency.

At page 8 in the Technical Rationale document, the drafting team argues that "To compensate for the lack of inertia and short circuit contributions, [IBRs] should have wider tolerances for frequency and voltage excursions to meet the needs of future power systems with a higher percentage of IBR." The drafting team also argues that IBRs should have to ride-through much larger frequency deviations than synchronous resources because "Synchronous resources are more sensitive to frequency deviations than IBR resources." This logic is flawed for many reasons. Grid operators need all resources to ride through disturbances, and the contribution of a resource to inertia or short circuit needs is irrelevant to that need. Any concerns about resources' inertia and short circuit contributions are outside the drafting team's scope and authority, and should be addressed by other means (such as by increasing the deployment of grid-forming IBRs in the localized areas that have short circuit or stability concerns). It is also perverse for the drafting team to penalize IBRs for being less sensitive to frequency deviations than synchronous generators. As noted below, there are already grounds for FERC to reject this proposed standard due to undue discrimination against IBRs relative to the far more lenient requirements on synchronous generators under PRC-024, including an equipment limitation exemption for synchronous generators from the frequency relay setting requirement in PRC-024, and this only adds to those concerns.

In short, the drafting team's unfounded concerns about a future power system do not justify withholding an exemption to frequency ride-through requirements for existing IBR resources that will have been largely replaced by the time any concerns might materialize.

Finally, R4 equipment limitation exemptions should be allowed for resources with signed interconnection agreements as of the effective date of the Standard, instead of resources that are in-service as of that date. Resource equipment decisions are typically locked down at the time the interconnection agreement is signed, and a change in requirements after that point can require a costly change in equipment or settings that may also trigger a material modification and resulting interconnection restudies. The implementation plan for PRC-029 indicates that the effective date for the Standard will be the first day of the first quarter six months after FERC approval. Many resources take significantly longer than that to move from a signed interconnection agreement to being placed in service, so it makes more sense to allow R4 equipment limitation exemptions for resources that have a signed interconnection agreement as of the effective date of the Standard.

The current draft of the PRC-029 Standard is unworkable and will impose massive costs on some existing generators with no benefit for reliability. As explained above, the drafting team incorrectly ventures that "IBR should be capable of riding through the increased proposed 6-second frequency ride-through requirement without risk of equipment damage or need for frequency protection to operate," even after noting that some wind turbines use very different technology. NERC's rigorous standard development process exists to ensure that errors like this do not make it into final Standards, and the exceedingly low level of support for the initial draft and the major revisions in the current draft indicate that further revisions will likely be necessary.

It takes time to fine tune highly technical requirements and vet them across the industry to avoid unnecessary and exorbitant costs for existing resources that cannot meet the standard. If the drafting team and NERC believe Order No. 901's deadlines do not provide enough time for further standard revisions and balloting periods to make the frequency ride-through requirement workable for existing resources, adding the letters "R3" to R4 to create an exemption for existing resources is the fastest and easiest way to address those concerns. For the reasons explained above, such an exemption does not pose any risk to reliability and is consistent with FERC's directive in Order 901.

Undue discrimination

A major concern with the Standards, as drafted, is that ride through performance is not required for synchronous generators under PRC-024-4, but it is for IBRs under PRC-029. PRC-024 simply requires protective relays to be set so they do not trip the generator within specified bounds, but it allows a resource to trip offline for other reasons. PRC-024-4 also allows a plant to trip if protection systems trip auxiliary plant equipment, per section 4.2.3. In contrast, PRC-029 requires IBRs to remain electrically connected and to continue to exchange current within the specified voltage and frequency bounds. Said another way, an IBR and a synchronous resource could both trip during the same disturbance, and the IBR would be in violation of PRC-029 but the synchronous generator would not be in violation of PRC-024-4, as long as the synchronous generator did not trip due to the settings of its protection system.

To ensure grid reliability and resilience, all resources including IBRs and synchronous resources should ride through grid disturbances. The failure of synchronous generators to ride through grid disturbances threatens grid reliability as much or more than the failure of IBRs, as synchronous resources are often producing at a higher level of output, are more typically relied on as capacity resources, and often take longer to come back online and ramp up to full output if they trip due to a disturbance.

FERC Order No. 901 directed NERC to treat IBR resources similarly to how NERC Standards treat synchronous generators, writing that the IBR Standard should "permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults."{C}[15] Allowing synchronous generators to trip but requiring IBRs to ride through the same or similar disturbance will be challenged at FERC as undue discrimination. Providing synchronous generators with an equipment limitation exemption from PRC-024's relay-setting requirements but not offering existing IBR resources an exemption from the far more stringent frequency ride-through requirements in PRC-029 is also undue discrimination.

This disparate treatment of IBRs versus synchronous generators is also at odds with the intent for this project that NERC stated in its February 2023 comments on the FERC proposed rulemaking that led to Order No. 901: "A comprehensive, performance-based ride-through standard is needed to assure future grid reliability. To that end, NERC re-scoped an existing project, Project 2020-02 Modifications to PRC-024 (Generator Ride-through), to revise or replace current Reliability Standard PRC-024-3 with a standard that will require ride-through performance from all generating resources."[16] FERC's Order No. 901 also noted NERC's statement that this project would require ride-through performance from all generating resources,[17] so a failure to require ride-through performance from synchronous generators is contrary to both NERC's and FERC's intent.

Providing an exemption in PRC-029 R4 for existing IBRs that cannot meet the frequency ride-through requirement in R3 will result in less disparity with the treatment of synchronous resources under PRC-024, and is therefore an essential step if NERC wants to reduce the risk of FERC rejecting the proposed standard due to undue discrimination against IBRs.

{C}[1]{C} Technical Rationale, PRC-029-1 – Frequency and Voltage Ride-Through Requirements for Inverter-Based Generating Resources, at 8, https://www.nerc.com/pa/Stand/202002_Transmissionconnected_Resources_DL/2020-02_PRC-029-1_Technical_Rationale_Redline_to_Last_Posted_06182024.pdf ("Technical Rationale").

{C}[2]{C} *Id.*, at 10

{C}[3]{C} *Reliability Standards to Address Inverter-Based Resources*, Order No. 901, 185 FERC ¶ 61,042, P 193 (2023).

{C}[4]{C} For example, **Section 215(d)(2) of the FPA** requires FERC to give "due weight" to the technical expertise of the ERO when evaluating the content of a proposed Reliability Standard or modification to a Standard.

Order No. 733-A, P 11: "In this order, we emphasize and affirm that we do not intend to prohibit NERC from exercising its technical expertise to develop a solution to an identified reliability concern that is equally effective and efficient as the one proposed in Order No. 733."

Order No. 748, P 43: "In consideration of these ongoing efforts, we will not direct specific modifications to these Reliability Standards and, rather, accept NERC's commitment to exercise its technical expertise to study these issues and develop appropriate revisions to applicable Standards as may be necessary."

Order No. 896, P 36: "NERC may also consider other approaches that achieve the objectives outlined in this final rule. Further, as recommended by PJM, we believe there is value in engaging with national labs, RTOs, NOAA, and other agencies and organizations in developing benchmark events. Considering NERC's key role, technical expertise, and experience assessing the reliability impacts of various events and conditions, we encourage NERC to engage with national labs, RTOs, NOAA, and other agencies and organizations as needed."

Order No. 901, P 192: "We believe that, through its standard development process, NERC is best positioned, with input from stakeholders to determine specific IBRs performance requirements during ride through conditions, such as type (e.g., real current and/or reactive current) and magnitude of current. NERC should use its discretion to determine the appropriate technical requirements needed to ensure frequency and voltage ride through by registered IBRs during its standards development process."

{C}[5]{C} Order 901, P 193

{C}[6]{C} *Id.* at P 178.

{C}[7]{C} *Id.* at P 190.

{C}[8]{C} Technical Rationale at 7.

{C}[9]{C} East Interconnection Frequency Response Assessment with Inverter Based Resources, at 7 https://www.energy.gov/sites/prod/files/2018/07/f53/2.1.4%20Frequency%20Response%20Panel%20-%20Velummylum%2C%20NERC.pdf.

{C}[10]{C} Best Practices for Operation and Maintenance of Photovoltaic and Energy Storage Systems, at 55, https://www.nrel.gov/docs/fy19osti/73822.pdf.

{C}[11]{C}Fast Frequency Response Concepts and Bulk Power System Reliability Needs, https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf.

{C}[12]{C} Inertia and the Power Grid: A Guide Without the Spin, https://www.nrel.gov/docs/fy20osti/73856.pdf.

{C}[13]{C} East Interconnection Frequency Response Assessment with Inverter Based Resources, at 7 https://www.energy.gov/sites/prod/files/2018/07/f53/2.1.4%20Frequency%20Response%20Panel%20-%20Velummylum%2C%20NERC.pdf.

{C}[14]{C} https://www.nerc.com/pa/Stand/Project%20200712%20Frequency%20Response%20DL/FRI_Report_10-30-12_Master_w-appendices.pdf

{C}[15]{C} Order No. 901, at P190

[16]{C}https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Comments_IBR%20Standards%20NOPR.pdf, at 21-22.

[17]{C} Order No. 901, at P 185

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5

Answer	

Document Name	
Comment	

Thank you for the opportunity to provide comments and for your work on this project. Invenergy provides the below comments for the Drafting Team to consider:

R1: In response to industry comments, the SDT indicated that Requirement R5 from Draft 1 was removed, but it appears the phase-angle jump requirements have simply been reinserted under Requirement R1 in this second draft. As drafted, a facility is expected to ride-through fault-initiated switching events regardless of the magnitude of voltage phase angle change. Consider that positive sequence phase angle change cannot be accurately measured during a fault occurrence and clearance. We propose the assessment of ride-through performance during fault occurrence, clearance, and recovery be based only on the voltage ride-through criteria in Attachment 1 Table 1 and Table 2.

We recommend reverting the "Voltage (per unit)" columns of Table 1 and Table 2 back to their first draft state to remain consistent with Tables 11 and 12 of IEEE 2800.

R2.1.3: The decimal place is missing from "95 per unit."

R2.2: Consider more clearly defining "maximum capability." As an alternative, R2.2 could state, "…each IBR shall exchange current, up to the total sum of the nameplate current rating of online IBR units in the plant to provide voltage support…"

R2.3.1: Consider removal of this requirement. The time it should take a facility to restart current exchange following blocking seems irrelevant if the other ride-through performance requirements are being met.

Attachment 1: Note 11 from Attachment 1 should be removed. There are many equipment protection settings that are near instantaneous to protect against current or voltage surges that far exceed the equipment's maximum rating. A power electronic switch could burn out in a matter of micro-seconds due to such a surge, before any tripping decision could be made if the filtering length must be at least 16.6 milliseconds.

R3: We recommend reverting the "System Frequency (Hz)" columns of Table 3 back to its first draft state to remain consistent with Tables 15 of IEEE 2800.

The Consideration of Comments document seemed to indicate that the drafting team intended to respond to our previous comment regarding the expansion of the frequency ride-through range, but none was provided. The proposed 6-second frequency ride-through capability requirement for the ranges of 61.8Hz to 64Hz and 57Hz to 56Hz does not align with the requirements on the rest of the BES and would expose synchronous generators to dangerous variations in frequency. Can the drafting team cite more specific reasoning or data to support the expansion of the frequency ride-through capability requirement to the range of 64Hz to 56Hz, well beyond the IEEE 2800-2022 standard frequency ride-through requirement and the capabilities of many legacy IBRs?

R4: We recommend the following revision to R4.

R4. Each Generator Owner and Transmission Owner identifying a facility with a signed interconnection agreement by the effective date of PRC-029-1 with known hardware limitations that prevent the facility from meeting ride-through criteria as detailed in Requirements R1, R2, and R3, and requires an exemption from specific ride-through criteria shall:

Exemptions in R4 should be based on the execution of the interconnection agreement rather than the in-service date of the facility. As drafted, facilities with executed interconnection agreements, but not yet in-service by the effective date of the standard may need to make significant equipment modifications and perform interconnection restudies to comply with requirements that did not become effective until after the interconnection agreement was executed.

Regarding the lack of frequency ride-through exemptions, the limited exception language in FERC Order 901 is not supported by any comments or other evidence in the record in the original NOPR proceeding, and therefore we believe this to be an inadvertent omission and unjustified application of Order 901 in the draft language of PRC-029-1. In fact, in the NOPR, FERC proposed to direct NERC "to develop new or modified Reliability Standards that would require Generator Owners and Generator Operators to ensure that their registered IBR facilities ride through system frequency and voltage disturbances **where technologically feasible**." The drafted frequency ride-through performance requirements are not technologically feasible for many legacy IBRs.

Further, in Order 901, FERC "encourage[s] NERC's standard drafting team to consider currently effective Reliability Standard PRC-024-3, Requirement R3 as an example for establishing registered IBR technology exemptions." Requirement R3 of PRC-024-3, and the currently drafted version of PRC-024-4, allows for exemptions from both the frequency and voltage ride-through requirements due to equipment limitations.

Given the lack of a clear evidentiary record on this point, the drafting team should rely on the discretion FERC has always granted NERC when it comes to drafting and implementing practical Reliability Standards. Invenergy recommends Requirement R4 be amended to allow limited exemptions from specific voltage and frequency ride-through criteria for facilities with known hardware limitations that prevent the facility from meeting the ride-through criteria detailed in Requirements R1, R2, and R3.

Finally, Invenergy has concerns regarding the deviation of this project from its original goal of developing a standard that will require ride-through performance from all generating resources. As currently drafted, PRC-024-4 imposes fewer ride-through performance responsibilities on synchronous generators while allowing broader exemptions from its requirements than PRC-029-1. This undue discrimination permits scenarios in which both a synchronous generator and an IBR could trip offline due to the same system disturbance and only the IBR would be subject to a potential noncompliance, assuming the synchronous generator did not trip due to its protection system settings.

Implementation Plan: In its Consideration of Comments, the drafting team indicated that the Implementation Plan has been modified such that PRC-029-1 shall become effective on the first day of the first calendar quarter that is 12 months after the effective date of the applicable governmental authority's order approving PRC-028-1, however the Implementation Plan still lists an implementation timeframe of six months.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

Southern Company supports NAGF comments.

Southern Company suggests that M1 be divided out to be clearer such as:

M1. Each Generator Owner and Transmission Owner shall have evidence of dynamic simulations, studies, or other evidence to demonstrate the design of each facility will adhere to Ride-through requirements, as specified in Requirement R1.

M1.1 Each Generator Owner and Transmission Owner shall have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) to demonstrate that the operation of each facility did adhere to Ride through requirements, as specified in Requirement R1.

M1.2 If the Generator Owner and Transmission Owner choose to utilize Ride-through exemptions that occur within the "must Ride-through zone" and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner and Transmission Owner shall also have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate that the facility failed to Ride-through during a phase jump of greater than or equal to 25 electrical degrees, and documentation from their Transmission Planner, Reliability Coordinator, Planning Coordinator, or Transmission Operator that a non-fault initiated switching event occurred.

Southern Company suggests adding an exemption for V/Hz to R3 like bullet 4 in R1.

R3 - Frequency Ride-Through Criteria

Southern Company recommends PRC-029-1 adopt Frequency Ride-Through Criteria (Attachment 2, Table 3 in draft 2) consistent with the IEEE2800 standard. Individual Regions should be allowed to adopt more stringent frequency ride-through standards based on their respective system needs and resource capabilities.

R4 – Exemptions

Any ultimate decision to disallow exemptions for requirements other than voltage, must be grounded in a thorough technical analysis of IBR OEM capabilities. NERC staff and standard drafting team participants have the necessary technical expertise to make these determinations. Additionally, there is ample precedent from prior Standard processes for FERC to defer to NERC on such technical issues. Finally, if the more stringent Frequency Ride-Through criteria in the current draft is preserved, this amplifies the need for consideration of existing equipment frequency ride-through exemptions. GOs and OEMs have not had adequate time to assess resource capabilities against requirements more stringent than IEEE2800.

Southern Company suggests that Requirement R4.3 be reworded to "...that replace the equipment causing the limitation, such that the limitation no longer exists, shall document and communicate..." The current wording is being interpreted that the only equipment that can be put back in place of a failed piece of equipment with a limitation is one without a limitation. Furthermore, R4.3.1 alludes that replacement of equipment with a limitation must be made with equipment without limitation. This may not be possible due to uniqueness and limits associated with an existing facility design. There is no allowance for in-kind replacements. If one inverter burns down, there is no provision to replace it with an in-kind spare replacement unit.

Note 7 on page 15 states that you only have to ride-through the voltage deviations if the frequency remains within the "must ride through zone". Doesn't there need to be a corresponding statement made on page 19? In other words, the standard should allow you to trip even if the frequency remained at a constant 60Hz if the voltage does not remain within the values in Attachment 1.

Southern Company suggests that Requirement R4 also include identified "software limitations" in addition to hardware limitations.

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1

Answer	
Document Name	

Comment

TEPC does not have any comments for PRC-024-4.

TEPC agrees with EEI's comments regarding PRC-019-1.

Likes 0	
Dislikes 0	

Response

Darcy O'Connell - California ISO - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee	
Answer	
Document Name	
Comment	

Ride-through Definition:

The ISO RTO Council Standards Review Committee (SRC) recommends that the drafting team provide a rationale for the proposed "Ride-through" definition, as it is not clear what benefits result from creating a formal definition for this term, and the definition that has been proposed contains ambiguous language.

First, use of the term "synchronized" in a definition intended to apply to IBRs could result in confusion because IBRs are generally considered to be asynchronous resources (though no mention of IBRs is made in the proposed definition). As a stand-alone term in the NERC glossary, the proposed definition could reasonably be interpreted to apply only to synchronous machines.

Second, the phrase "continuing to operate" is an inadequate description of desired performance – ride-through should include a concept of performance that is beneficial (or at the very least not detrimental) to overall grid reliability.

Third, the use of "Transmission System" potentially limits the applicability of the definition to only transmission-connected resources – the SDT may want to consider instead using a more general term such as "electric system" as was used in the proposed IBR definition.

Finally, defining the term "ride-through" may not be necessary at all. Meeting all of the requirements in PRC-029 essentially constitutes ride-through. Creating a separate defined term may just cause confusion, as the proposed definition does not clarify the desired (or required) performance associated with ride-through. The best option may be to leave the term undefined. If the SDT determines that a definition for Ride-though is an absolute necessity, the SRC proposes the following definition:

"Facilities, including all individual dispersed power producing resources, remaining connected to the electric system and continuing to operate in a manner that supports grid reliability throughout a System Disturbance, including the period of recovery back to a normal operating condition."

Comments on Proposed Requirements:

The language in PRC-029-1 Requirement R2, Part 2.1.3 that reads "…according to requirements if required by the [TP, PC, RC, or TOP]" seems awkward and redundant, as it seems that any requirements that exist will always be required.   The SRC recommends that this language be changed to: "…according to TP, PC, RC, and TOP requirements, if any." Additionally, if the SDT continues to use a per unit metric for Part 2.1.3, the proposed "95 per unit" should be replaced with ".95 per unit . . . ."

Regarding PRC-029-1 Requirement R2, Part 2.2, it can be problematic to simply specify reactive/active power priority because not all priority implementations perform the same way. Part 2.2 does not really prohibit dropping active current to zero even for shallow voltage dips (e.g. 0.7-0.9pu), but seems to allow the TP, PC, RC, or TOP to specify the desired performance. The SRC requests that the SDT clarify whether this is the intended meaning, and revise Part 2.2 as necessary to clarify the intended meaning.

PRC-029-1 Requirement R2, Part 2.5 reads "…when the voltage at the high-side of the main power transformer returns from the mandatory operation region…." The SRC requests that the SDT clarify whether this was intended to read: "when the voltage at the high-side of the main power transformer returns **to the continuous operation region** from the mandatory operation region…."

In R2, Part 2.5 "available level (whichever is less)" should be revised to clarify whether "a lower post-disturbance active power level requirement" means lower than the pre-disturbance level or lower than the available level.

The SRC also notes that the phrase "…pre-disturbance or available level (whichever is lesser)…" in PRC-029-1 Requirement R2, Part 2.5 may be interpreted as allowing partial tripping/idling for an IBR facility. If the SDT's intent is that no individual wind turbines/inverters should be allowed to trip/idle, SRC recommends that this phrase be clarified with a footnote such as: "Reduction in available active power shall only be allowed due to a reduction in available source power (e.g. wind or solar irradiance). Reduction in available active power shall not occur due to tripping or idling of individual turbines or inverters within the IBR."

The SRC requests that the SDT clarify whether Requirement R1 should include an absolute rate of change of voltage criteria similar to the RoCoF criteria in PRC-029-1 Requirement R3. The SRC also requests clarification of whether the other bulleted exceptions listed in Requirement R1 apply during frequency excursions (in other words, the SRC requests clarification of whether ride through is required for frequency excursions even if the thresholds for V/Hz or phase angle jump specified in Requirement R1 are exceeded).

The SRC is concerned that the word "replaced" in PRC-029-1 Requirement R4, Part 4.3.1 may provide a pathway to circumvent the spirit of the standard (e.g., an entity could refurbish equipment and claim that its exemption should be maintained because equipment wasn't "replaced"). The SRC recommends that "replaced, refurbished, or updated" be used instead. At the very least, the Technical Rationale should explain that documented limitations are expected to be eliminated whenever an IBR is re-powered, upgraded, or updated with significant re-investment.

In PRC-029-1, Attachment 1, Tables 1 and 2 use the term "operation region" while Figures 1 and 2 use the term "operating regions." If the two terms are intended to have the same meaning, the SRC recommends that the same term be used in both locations (and throughout the standard). If the two terms are intended to have different meanings, the SRC recommends that the intended meanings be clarified.

In PRC-029-1, Attachment 1, item 7 references a "must ride-through zone" in Table 3 of Attachment 2. However, Table 3 of Attachment 2 does not explicitly specify a "must ride-through zone." The SRC recommends that the SDT clarify whether Attachment 1, item 7 was intended to reference Figure 3 of Attachment 2, or otherwise clarify the intended meaning. The SRC also requests that the SDT clarify why Attachment 2 does not have a corollary item specifying that Table 3 is only applicable when voltage is within the "must ride-through zone" specified in Attachment 1. The SDT should update the Technical Rationale to clarify the intent: whether there is a need to verify or not to verify voltage status for the Table 3 Attachment 2.

The SRC notes that the Technical Rationale for PRC-029-1 contains what appears to be an extraneous "Must Ride-through" heading between the rational for R2.5 and the rationale for R3. The SRC recommends removal of this extraneous heading.

The SRC notes that the Technical Rationale for PRC-024-4 makes no explicit mention of the addition of type 1 and type 2 wind resources to PRC-024-4 and refers to restricting the applicability of PRC-024-4 to synchronous generators and synchronous condensers, which does not appear to be consistent with the posted redlines for PRC-024-4. The SRC recommends that PRC-024-4 and the Technical Rationale be harmonized to remove this discrepancy.

The applicability section for PRC-029-1 references "IBR Registration Criteria," which presumably is intended to include IBRs connected to the BPS that are not considered BES Elements (consistent with the pending revisions to the registration criteria for IBRs). The SRC notes that the Technical Rationale is not very clear on the intent of this structure and requests that a more detailed explanation be included in the Technical Rationale.

Finally, the SRC notes that the addition of type 1 and type 2 wind resources to PRC-024-4 appears to be limited to facilities that meet the BES definition. The SRC requests that the SDT clarify whether this difference is intentional and, if it is, provide the rationale for the difference (such as if the revisions to NERC's registration criteria are not intended to apply to non-BES type 1 or type 2 wind resources) and an explanation of whether the difference constitutes a potential gap that should be addressed.

Comments on Attachment 1: Voltage Ride-Through Criteria

Attachment 1 lists a minimum ride-through time of 1800 seconds for the continuous operation voltage region between 1.05 pu and 1.1 pu (<= 1.1 and >1.05) in Tables 1 and 2. The SRC requests that, consistent with IEEE 2800, an exception for 500 kV systems be allowed such that the minimum ride-through time for 1.05 pu < voltage <= 1.1 pu for 500 kV systems is "Continuous," because the 1.05 pu < voltage <= 1.1 pu voltage range is within the normal operation range for some systems, such as PJM's system.

In addition, in Figures 1 and 2, the SRC requests that the voltage pu values on Y-axis for the "Continuous Operating Region (1800 seconds)" be revised to be consistent with the values listed in Tables 1 and 2 (1.05 < and <= 1.1).

Finally, the SRC generally supports incorporating as much of the IEEE 2800 language and parameters into PRC-029-1 as possible, and the SRC encourages the drafting team to lean on IEEE 2800 as much as is feasible.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

Electric Reliability Council of Texas, Inc. (ERCOT) joins the comments submitted by the ISO/RTO Council Standards Review Committee (SRC) and adopts them as its own. In addition, ERCOT submits the following comments.

ERCOT notes that the proposed Ride-through definition is unclear as to whether ride-through applies to partial trips (individual inverter or turbine trips). ERCOT believes ride-through should apply both to the IBR facility and to the individual IBR units and requests that this be made clear in any definition that may be adopted. If a defined term for ride-through is implemented, ERCOT recommends the use of a clarification modeled after the I4 inclusion ("dispersed power producing resources") in the BES definition, as detailed in the SRC's proposed definition:

"Facilities, including all individual dispersed power producing resources, remaining connected to the electric system and continuing to operate in a manner that supports grid reliability throughout a System Disturbance, including the period of recovery back to a normal operating condition."

Additionally, ERCOT has identified the following concerns with Requirement R1 as it is currently proposed:

1.) R1 does not clarify whether partial trips (individual IBR unit trips) would be allowed. ERCOT believes individual turbine/inverter trips should not be permissible under R1 and that R1 should clearly indicate that ride-through does not occur when individual turbines or inverters trip offline.

2.) Requirement R1's reference to "adhering" to requirements may create the mistaken impression that exceeding the minimum ride-through requirements is not allowed.

3.) Allowing an exclusion from Requirement R1 for equipment limitations should not result in a unit being exempt from complying with requirements that are not impacted by the limitation.

4.) The process for obtaining a documented limitation should be reviewed to ensure it is consistent with the directives that FERC included in its recent Order on EOP-011-2 in Docket No. RD24-5-000.

To address these issues, ERCOT recommends that Requirement R1 be revised to read as follows:

R1. Each Generator Owner or Transmission Owner shall ensure the design and operation is such that each facility ***meets or exceeds*** the Ride-through requirements, in accordance with the "must Ride-through3 zone" as specified in Attachment 1, except for the following: [Violation Risk Factor: High] [Time Horizon: Operations Assessment]

• The facility needed to electrically disconnect in order to clear a fault;

• ***The electrical system at the high-side of the main power transformer demonstrated characteristics that exceeded a*** documented ***and confirmed*** equipment limitation identified and communicated in accordance with Requirement R4; or

• The instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer and is initiated by a non-fault switching event on the transmission system; or

• The Volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

3 Includes no tripping associated with phase lock loop loss of synchronism; additionally, individual inverter or turbine tripping is not allowed.

ERCOT also recommends that Requirement R2, Part 2.1 and the surrounding language be reviewed and revised to clarify that the facility should continue to deliver the pre-disturbance level of current as appropriate, since power depends on voltage. In principle, during a disturbance active power should only reduce proportionally to voltage such that active current is consistent unless needed for frequency response. Reactive current should adjust as needed to support voltage (lead or lag as appropriate) up to its current limits. In general, the Requirement should neither incentivize entities to undersize inverters/converters nor impose onerous requirements to oversize this equipment. This lack of clarity may cause issues in enforcing this requirement and miss the reliability objective.

In addition, requiring a facility to deliver reactive power "according to its controller settings" is impractical and misses the objective. The requirement should be to ensure the proper response performance, as each facility operates according to its controller settings, even if those settings happen to be incorrect.

To address these issues, ERCOT recommends that the following portions of Requirement R2 be revised to read as follows:

R2. Each Generator Owner or Transmission Owner shall ensure the design and operation is such that the voltage performance for each facility adheres to the following during a voltage excursion, unless a documented equipment limitation exists in accordance with Requirement R4. [Violation Risk Factor: High] [Time Horizon: Operations Assessment]

2.1.1 Continue to deliver the pre-disturbance level of active ***current***, unless a different level of current is needed for frequency response.

2.1.2 Continue to deliver reactive ***current*** up to its reactive ***current*** limit, as appropriate to control voltage to within normal System Voltage Limits.

2.1.3 If the facility cannot meet 2.1.1 and 2.1.2 due to an apparent, active, or reactive current limit, when the applicable voltage is below .95 per unit and still within the continuous operation region, then preference shall be given to active or reactive current ***as well as allowed levels of reduction***, according to the Transmission Planner, Planning Coordinator, Reliability Coordinator, and Transmission Operator requirements.

2.6 Individual dispersed power producing resources must Ride-Through.

ERCOT appreciates the SDT's work on the purpose statement and believes that the purpose statement can be further clarified and simplified if it is revised to place the focus on PRC-029-1's intended effect of ensuring the units and facilities ride-through and perform as expected instead of focusing on "adhering" to requirements.

To achieve this objective, ERCOT recommends that the purpose statement be revised to read as follows: "To ensure that Inverter-Based Resources (IBRs) ride-through, during and after, defined frequency and voltage excursions while performing operationally as expected to support the Bulk-Power System (BPS)."

ERCOT is aware of an overarching concern that the RoCoF and phase angle jump requirements may be difficult to enforce for partial IBR tripping. Addressing this concern may be a matter of coordination of DFRs. If individual IBR units trip but the plant does not, DFRs may not trigger. PMUs would most likely not be fast enough to record the frequency or angle changes to validate performance. The appropriate NERC standard development teams should coordinate with each other to ensure that individual IBR unit trips trigger DFR recording.

ERCOT requests that the drafting team remove or provide additional explanation regarding the six-month gap between the PRC-028 effective date and the PRC-029 effective date in the Implementation Plan.

ERCOT also requests that the Implementation Plan be revised to clarify what constitutes being "in operation" (unit synchronization, full commercial operations, or some other milestone) for purposes of determining whether an IBR may be considered for a potential exemption under the Implementation Plan.

ERCOT encourages the SDT to review Requirement R4 and the Implementation Plan in their entirety and revise them as necessary to ensure they align with the directives regarding constraints and exemptions that FERC included in its recent Order on EOP-012-2 in Docket No. RD24-5-000. Each limitation should be confirmed before it is allowed to go into effect. ERCOT opposes the SDT's broad approach of allowing exemptions without some level of confirmation of the impact of the exemption, such as an evaluation of the reliability impact of the exemption by a PC, RC, TP, or TOP. ERCOT believes that it is important for reliability to specifically require that limitations be modeled and provided to the PC/RC/TP/TOP. This is important enough that it should be explicitly referenced in the standard and should be required if a limitation is to be allowed/confirmed. Otherwise, the PC/RC/TP/TOP will receive limitations that cannot be modeled. A description of a limitation may not allow assessments and may limit determination studies that can be performed, resulting in a gap that reliability entities are expected to address, when the burden should be on generator owners to remove the limitation or improve the model fidelity. ERCOT believes the SDT's proposed approach misses the objective of FERC's directive that the RC/PC/TP/TOP should ensure that reliability is maintained while any allowed exemptions are in effect. PRC-029-1 should incentivize facility owners to explore whether less expensive upgrades can remove limitations rather than passing the burden of unmodeled limitations onto reliability entities that do not have the means to secure the system against limitations they cannot model properly.

Likes 0	
Dislikes 0	

Response

Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

Introduction

The Electric Power Research Institute (EPRI)[1] respectfully submits these comments (This Response) in response to North American Electric Reliability Corporation (NERC)'s request for formal comment on Project 2020-02 Modifications to PRC-024 (Generator Ride-through), issued on June 18, 2024.

EPRI closely collaborates with its members inclusive of electric power utilities, Independent System Operators (ISOs), and Regional Transmission Organizations (RTOs), as well as numerous other stakeholders, domestically and internationally. In its role, EPRI conducts independent research and development relating to the generation, delivery, and use of electricity for public benefit by working to help make electricity more reliable, affordable and environmentally safe. EPRI's comments on this topic are technical in nature based upon EPRI's research, development, and demonstration experience over the last 50 years in planning, analyzing, and developing technologies for electric power.

EPRI research and technology transfer deliverables are generally accessible on its website to the public, either for free or for purchase, and occasionally subject to licensing, export control, and other requirements.[2] The publicly available and free-of-charge milestone reports from a U.S. Department of Energy (DOE)- and EPRI member-funded research project, Adaptive Protection and Validated Models to Enable Deployment of High Penetrations of Solar PV ("PV-MOD"), substantiate many of the comments made in This Response.[3]

While not a standards development organization (SDO) itself, EPRI conducts research and demonstration projects in relevant areas as well as facilitates knowledge transfer and collaboration that SDOs may, at times, use to inform technical and regulatory standards development, such as in Institute of Electrical and Electronics Engineers (IEEE), International Electrotechnical Commission (IEC), International Council on Large Electric Systems (CIGRE), and NERC.[4]

EPRI's comments in This Response address reliability and NERC's draft PRC-029 Reliability Standards for IBRs ride-through requirements developed under project 2020-02. All comments are aimed at providing independent technical information to respond to the draft published by NERC based on EPRI's research and development results and associated staff expertise and do not necessarily reflect the opinions of those supporting and working with EPRI to conduct collaborative research and development. Where appropriate, EPRI's comments do not only address the specific questions of the NOPR but also related scope that may help to inform a final order. Some of EPRI's comments presented in This Response have also been submitted in response to the previous Federal Energy Regulatory Commission's (FERC) Notice of Proposed Rulemaking (NOPR) to direct North American Electric Reliability Corporation (NERC) to develop Reliability Standards for inverter-based resources (IBRs) that cover data sharing, model validation, planning and operational studies, and performance requirements (RM22-12), issued on November 17, 2022.

EPRI also submitted comments on the initial draft of PRC-029 which was issued on March 27, 2024. This 2nd set of EPRI comments supports the same direction as the previously submitted comments and offers a technical analysis based on the latest "Draft 2".[5]

Conclusion

EPRI appreciates the opportunity to provide NERC with its technical recommendations and comments on these important topics related to Reliability Standards for IBRs. EPRI looks forward to working with its members, NERC, and other stakeholders on providing further independent technical information on these important questions.

[1] EPRI is a nonprofit corporation organized under the laws of the District of Columbia Nonprofit Corporation Act and recognized as a tax-exempt organization under Section 501(c)(3) of the U.S. Internal Revenue Code of 1996, as amended, and acts in furtherance of its public benefit mission. EPRI was established in 1972 and has principal offices and laboratories located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass. EPRI conducts research and development relating to the generation, delivery, and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety, and the environment. EPRI also provides technology, policy and economic analyses to inform long-range research and development planning, as well as supports research in emerging technologies.

[2] https://www.epri.com (last accessed, April 22, 2024)

[3] PV-MOD Project Website. EPRI. Palo Alto, CA: 2024. [Online] https://www.epri.com/pvmod (last accessed, April 22, 2024)

[4] For transparency, we would like to disclose that EPRI collaborates with other organizations such as IEEE, IEC, CIGRE, and NERC; however, EPRI is not a regulatory- or standard-setting organization. EPRI research is often considered in the development of recommendations, guidelines, and best practices that are not determinative.

[5] https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx

Likes 0	
Dislikes 0	

Response

Wes Baker - Silicon Ranch - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

General

The SDT should consider specifying the grid conditions to which the ride-through requirements apply. The conditions should be bounded to some degree as the GO does not know the details of the transmission system and the range of operating conditions over the entire life of the plant.

R1

PRC-029 does not have an exception for transient overvoltage. This implies that the plant must ride through an unbounded transient voltage magnitude, which is unreasonable. Power electronic devices are sensitive to voltage and current. Equipment vendors and plant designers need to have clear performance requirements to design their equipment and plants to meet and be able to protect their equipment from damage when conditions are outside of these performance requirements. The SDT should consider adding an exception for transient overvoltage similar to IEEE

2800-2022 Clause 7.2.

R2
R2.1
Requirements for operating within the continuous operating range do not seem to be in scope with a ride-through standard. Additionally, these requirements are incomplete if the SDT intends to specify how the plant shall perform when voltage and frequency are within the continuous operating range. The SDT should consider removing R2.1.

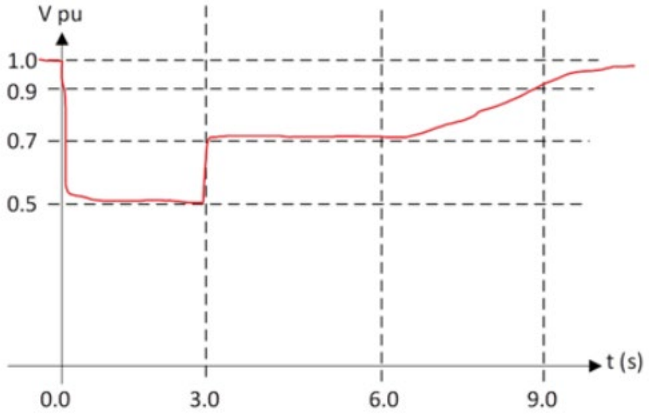
R2.2
- Given that this requirement is at the IBR plant level, it is unclear how 'maximum capability' is defined. The SDT should consider clarifying in the standard what the IBR plant's 'maximum capability'technically refers to.
- During a mandatory operating range, it is more appropriate to use 'current' rather than 'power' since power is a function of voltage. The SDT should replace all references to 'power' with 'current' for voltage outside the continuous operating range.
- The response of the IBR during HVRT and LVRT is typically dictated by the inverterlevel control based on inverter terminal voltage. The inverter does not have information about the high side of the main power transformer voltage at the required time scale. Additionally, there are multiple transformers with different winding configurations (e.g., delta, wye, wye-grounded) between the POI/POM where the PRC-029 requirement applies and the inverter terminal where the control is implemented. Using positive and negative sequence reactive current consistent with IEEE 2800-2022 Clause 7.2 is more practical than the 'affected phases.' The key is that the IBR should regulate the positive sequence and negative sequence voltage. This is the resulting effect of the IBR injecting positive and negative sequence reactive current based on positive and negative sequence voltage, /';'['respectively, and is consistent with how a synchronous machine naturally responds to asymmetrical disturbance. The SDT should consider making the current injection requirements applicable at the inverter terminal and based on sequence components consistent with IEEE 2800-2022 Clause 7.2.

R2.3.1
The use of 'positive sequence voltage' with respect to the continuous and mandatory operating range is not consistent with the rest of the standard which uses max/min of phase-phase or phase-ground fundamental frequency RMS voltage. For consistency, the SDT should change positive sequence voltage to max/min of phase-phase or phase-ground fundamental frequency RMS voltage.

R2.4
The requirement, as written, may not be practical for assessing compliance/noncompliance for the GO. The voltage at the IBR plant would also depend on the grid, including neighboring plants. Therefore, the IBR plant itself is unlikely to cause the plant to exceed the high voltage thresholds but certainly may contribute to the overvoltage. The SDT should consider removing this requirement and lumping it together with R2.2, adding requirements to the response time consistent with IEEE 2800-2022 Clause 7.2. If the IBR actively regulates the positive and negative sequence voltage quickly, the effect is as desired and can be readily assessed for compliance.

R3
The frequency ride-through requirements are much more stringent than IEEE 2800-2022 Clause 7.3. The SDT should provide more justification, beyond what is described in the Technical Rationale, as to why this range of frequency ride-through is required. Additionally, the SDT should ensure that due diligence has been done with vendors of the various equipment to ensure that this requirement is reasonable, and achievable with available technology.

Attachment 1
Tables 1 and 2 and numbered item 8
By using voltage bands (e.g., 0.7 <= V < 0.9) and time durations this results in a much more stringent requirement than IEEE 2800-2022 Clause 7. The SDT should consider removing the voltage bands to align with IEEE 2800-2022 Clause 7. Take this example where the red is a fictitious voltage plot:



Comparison of standards:

- IEEE 2800 Clause 7:
  - V < 0.9 pu ~ 8 seconds
  - V < 0.7 pu ~ 3 seconds
  - There is not an interpretation where the IBR has to ride through this LVRT in

IEEE 2800 Clause 7.

- PRC029 :
  - 0.7 <= V < 0.9 pu ~ 5 seconds.
  - 0.5 <= V < 0.7 pu ~ 3 seconds.
  - PRC-029 as written implies the IBR has to ride-through.

Numbered item 11
The standard should not specify how protection functions must be implemented. Instead, it should describe the required performance. Further, this requirement implies that the plant must ride through an unbounded voltage magnitude, which is not reasonable. As written, this item does not allow for tripping caused by excessive transient over-voltage (TOV) events. Power electronic devices are sensitive to voltage and current. Equipment vendors and plant designers need to have clear performance requirements to design their equipment and plants to meet and be able to protect their equipment from damage when conditions are outside of these performance requirements

Likes 0	
Dislikes 0	

Response

Comments received from LG&E/KU

Questions

2. Provide any additional comments for the Drafting Team to consider, if desired.

Comments:
All comments below pertain to PRC-029-1.

LG&E/KU agrees with the applicability concerns of EEI and suggests removing TOs and VSC-HVDC systems from this standard.

LG&E/KU also agrees with EEI that the requirements listing the TP, PC, RC, or TOP should clarify responsibility and include the responsible entity in the applicability of this standard. Alternatively, these listings may be sufficiently replaced with a requirement to adhere to applicable Facility interconnection requirements (e.g., “preference shall be given to active or reactive power according **to applicable Facility interconnection requirements**”).

The following additional comments are provided:

Requirement R1
Footnote 3 in Requirement R1 is unnecessary as the term “Ride-through” includes remaining synchronized.
The following edit should be made to Requirement R1 to clarify responsibility is only for Facilities (note “Facility” is a NERC defined term and should be capitalized) under the responsible entities ownership:
… shall ensure the design and operation ~~is such that each~~ **of its IBR Facilities** ~~facility~~ adheres to Ride-through requirements~~, in accordance with the “must Ride-through[3] zone” as~~ specified in Attachment 1, except for …
The following edit is suggested for bullet 1 under Requirement R1:
The ~~facility~~ **IBR Facility** ~~needed to~~ electrically disconnect**s** in order to clear a fault; **or**

Measure M1
Measure M1 adds to the scope of Requirement R1. Measures should only describe how compliance with the associated Requirement will be assessed, not add to the scope of the Requirement itself. For example, Measure M1 strongly suggests that “dynamic simulations” and “studies” are the only acceptable forms of evidence for determining ride-through capability. However, Requirement R1 does not have any explicit requirement to perform analysis.
Measure M1 also states disturbance monitoring data is required to demonstrate adherence to Ride-through requirements. It is unclear what is required here since IBR Facilities will be online and operating normally most of the time. The most recent draft of PRC-030-1 already includes requirements for analyzing “Ride-through performance” in situations where the IBR Facility significantly reduces active power output (which would include tripping). It is more appropriate to analyze failed Ride-through than it is to provide immense quantities of data showing the IBR Facility is operating normally.
Measure M1 references only one of the exceptions listed under Requirement R1.
The following edit is suggested for Measure M1 (responsibility issues should also be addressed, as noted previously):

Each Generator Owner ~~and Transmission Owner~~ **shall** have evidence of ~~dynamic simulations, studies, or other evidence to demonstrate~~ **that** the design **and operation** of each **of its IBR Facilities** ~~facility will~~ adhere**s** to **the** Ride-through requirements~~, as~~ specified in **Attachment 1**~~Requirement R1. Each Generator Owner and Transmission Owner have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) to demonstrate that the operation of each facility did adhere to Ride-through requirements, as specified in Requirement R1. If the Generator Owner and Transmission Owner choose to utilize~~ **If failed** Ride-through **occurs for conditions exempted in Requirement R1** ~~exemptions that occur within the “must Ride-through zone” and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then~~ each Generator Owner ~~and Transmission Owner~~ **shall** ~~also~~ have evidence of **the conditions** ~~actual disturbance monitoring (i.e. Sequence of Event~~

~~Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate that the facility failed to Ride-through during a phase jump of greater than or equal to 25 electrical degrees, and documentation from their Transmission Planner, Reliability Coordinator, Planning Coordinator, or Transmission Operator that a non-fault initiated switching event occurred~~.

Requirement R2

Requirement R2 addresses performance during the Ride-through conditions of Requirement R1 and should establish a clear link. There is also inconsistency in that Requirement R2 only exempts documented equipment limitations and none of the other exemptions in Requirement R1. The following edit is suggested for Requirement R2:

… shall ensure the design and operation ~~is such that~~ **of** the voltage performance ~~for~~ **of its IBR Facilities** ~~each facility~~ adheres to the following during **conditions requiring Ride-through** ~~a voltage excursion, unless a documented equipment limitation exists~~ in accordance with Requirement R**1**4.

Each part of Requirement R2 refers to the "voltage at the high-side of the main power transformer". Attachment 1 already states in item (6) that the applicable voltage is at the high-side of the main power transformer. Thus, each part of Requirement R2 should be condensed as follows:

~~While the voltage at the high-side of the main power transformer remains w~~**W**ithin the continuous operation region ~~as~~ specified in Attachment 1, ~~each facility~~ **IBR Facilities** shall:

Requirement R2 part 2.1.2 should be removed. Delivering reactive power "up to its reactive power limit and according to its controller settings" wouldn't appear to be anything other than normal operation.

Requirement R2 part 2.1.3 is clearly intended to mirror a similar requirement in IEEE 2800-2022 subclause 7.2.2.2. However it makes two errors, and unnecessarily restates the voltage is in the continuous operating region (Requirement R2 part 2.1 already includes this condition). Correct as follows:

If the **IBR Facility** ~~facility~~ cannot deliver both active and reactive power due to a current limit or ~~reactive~~ **apparent** power limit, when the voltage is below **0.**95 per unit ~~and still within the continuous operation region~~, then preference shall be given to active or reactive power according to requirements ~~if required by~~ **of** the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

It is understood that the DT had "apparent power limit" in the first draft of this standard and has now replaced it with "reactive power limit" following comments. However, this is an error. The apparent power limit is a limit of the inverter and not the PPC as suggested in some of the comments. IEEE 2800-2022 correctly states the limit is "apparent" power. I.e., an inverter has an MVA limit and there may be times when the inverter is called on to produce more total MVA (MW and MVAR) than it is able to. It is in this case that the inverter must prioritize MW or MVAR.

The language of Requirement R2 part 2.2 is unnecessarily confusing. Attachment 1 already indicates the boundaries of the mandatory operating region and they are delineated by RMS voltages. Suggested simplification and clarification:

~~While voltage at the high-side of the main power transformer is w~~**W**ithin the mandatory operation region ~~as~~ specified in Attachment 1, ~~each~~ **an** IBR **Facility** shall **continue to** exchange current~~,~~ up to ~~the~~ **its** maximum **limit** ~~capability to~~ **and** provide voltage support**.**~~, on the affected phases during both~~

~~symmetrical and asymmetrical voltage disturbances, either under~~[6]~~: •~~ **IBR Facilities shall operate in** ~~R~~**r**eactive power priority by default~~;~~**,** or~~•~~ **in** ~~A~~**a**ctive power priority if required by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Footnote 6 is unnecessary for this standard. Entities that wish to specify the magnitude of current injections during disturbances should do so in their Facility Interconnection Requirements.

Suggesting the following simplification of Requirement R2 part 2.3.1:

If a**n IBR Facility** ~~facility~~ enters current block**ing** mode, it shall restart current exchange in less than or equal to five cycles of ~~positive sequence voltage~~ returning to **the** ~~a~~ continuous operation region or mandatory operation region.

Suggesting the following simplification of Requirement R2 part 2.5:

~~Each facility~~ **IBR Facilities** shall restore active power output to the pre-disturbance or available level~~ (~~**,** whichever is less~~er)~~**,** within 1.0 second ~~when the voltage at the high-side of the main power transformer~~ **upon** return**ing**~~s~~ ~~from the mandatory operation region or permissive operation region (including operating in current block mode),~~ **to the continuous operating region** as specified in Attachment 1, unless the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator **specifies otherwise** ~~requires a lower post-disturbance active power level requirement or requires a different post-disturbance active power restoration time~~.

Footnote 7 introduces confusion as it pertains to “frequency excursions” which is taken to mean conditions necessitating Ride-through. In this case, Requirement R3 and R4 would apply. Suggesting removal of this footnote.

Requirement R3

Suggesting the following simplification of Requirement R3 (to align with suggestions for Requirement R1):

… shall ensure the design and operation ~~is such that each facility~~ **of its IBR Facilities** adheres to Ride-through requirements ~~during a frequency excursion event whereby the System frequency remains within the “must Ridethrough zone” according to~~ **specified in** Attachment 2 ~~and~~ **when** the absolute rate of change of frequency (RoCoF)[8] magnitude is less than or equal to 5 Hz/second.

Measure M3

Measure M3 oversteps Requirement R3 similar to the M1/R1 discussion above. Suggested revision:

Each Generator Owner and Transmission Owner **shall** have evidence ~~of dynamic simulations, studies, or other evidence to demonstrate~~ **that** the design **and operation** of each **of its IBR Facility** ~~facility will~~ adhere**s** to **the** Ride-through requirements~~, as~~ specified in **Attachment 2** ~~Requirement R3. Each Generator Owner and Transmission Owner also have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate the operation of each facility did adhere to~~ **If failed** Ride-through ~~requirements, as specified in Requirement R3, during each frequency excursion event measured at the high-side of the main power transformer~~ **occurs for RoCoF magnitude greater than 5 Hz/second, each Generator Owner and Transmission Owner shall have evidence of the condition.**

Requirement R4

Requirement R4 is unwisely linked to the effective date of PRC-029-1. This makes sense at the initial effective date, but it excludes IBR Facilities that come in-service *after* the effective date. Further, it doesn't address failure to meet *frequency* Ride-through requirements. It appears to unnecessarily call out hardware limitations when software limitations can also be problematic. Finally, it seems to imply an exemption process exists but does not say who can grant an exemption or what the requirements for exemption are (e.g., is it subject to approval of the technical documentation?). The following revision is suggested:

If a ~~Each~~ Generator Owner ~~and Transmission Owner~~ identifi**es**~~ying~~ **one of its IBR Facilities** ~~facility that is in-service by the effective date of PRC-029-1,~~ has known ~~hardware~~ limitations that prevent ~~the facility from~~ meeting ~~voltage~~ **the** Ride-through requirements ~~criteria as detailed in~~ **of** Requirements R1**, R2,** ~~and~~ **or** R**3**~~2~~, ~~and requires an exemption from specific voltage Ride-through criteria~~ **the Generator Owner** shall:

Below are suggested edits in various parts of Requirement R4 to align with the body of R4 suggested above:

(4.1) Document ~~information supporting~~ the ~~identified~~ ~~hardware~~ limitation no later than 12 months ~~following the effective date of PRC-029-1~~ **after it is identified**.

(4.1.2) Which aspects of voltage **or frequency R**~~r~~ide-through requirements ~~that~~ the IBR **Facility is** ~~would be~~ unable to meet and the capability of the equipment due to the limitation;

(4.1.4) Supporting technical documentation ~~verifying~~ **explaining** if the limitation is due to hardware that needs to be physically replaced or ~~that~~ **if** the limitation can~~not~~ be removed by software updates or setting changes, and;

(4.2) **Request an exemption from [whom?] by p**~~P~~rovid**ing**~~e~~ a copy of the information detailed in Requirement R4.1 to the applicable Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and to the Regional Entity no later than 12 months ~~following the effective date of PRC-029-1~~ **after the limitation is identified**.

(4.2.1) Any response to additional information requested by the applicable Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), ~~and to the~~ **or** Regional Entity shall be provided ~~back to the requestor~~ within 90 days of the request.

(4.3) Each Generator Owner and Transmission Owner with a previously submitted request for exemption that ~~replace the equipment causing~~ **corrects** the limitation shall document and communicate ~~such an equipment change~~ **the correction** to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the **correction** ~~equipment change~~.

(4.3.1) When ~~existing equipment is replaced~~ **an exempted Ride-through limitation is corrected**, the exemption ~~for that Ride-through criteria~~ no longer applies.

Much of Requirement R4 concerns an exemption process which is poorly defined. Other standards, including others currently being developed for IBRs due to FERC directives, have utilized language requiring "Corrective Action Plans" for certain failures. The DT should consider if alignment with these standards is appropriate and should revisit the scope of the SAR for this project. Regardless, the DT must address several key issues that it has created by introducing the exemption language:

- Who grants the exemption?
- How long does the approving entity have to grant or deny an exemption?
- Is an IBR Facility out of compliance if it has requested an exemption but the exemption has not yet been granted?
- Is there still a requirement to fix the issue if you have an exemption?
- What if an IBR Facility is unable to meet the Ride-through requirements without a significant investment (e.g., replacing every inverter with new models)?

Measure M4

Measure M4 should be substantially revised to reflect the concerns addressed in the comments above.

Attachment 1

Regarding Table 1 of Attachment 1, row 2 appears to use the incorrect operator and should be corrected as follows: "≤ 1.20 and > 1.1".

Row 4 of Table 1 and Table 2 lists "Continuous" as a time where "∞" would be more appropriate.

It is recommended to remove footnotes 12 and 14 and place "May Ride-through Zone" directly into the table, e.g., "N/A (May Ride-through Zone)".

Item (2)(b) of Attachment 1 references "hybrid plants consisting of photovoltaic (PV) and BESS" but does not address hybrid plants with other components. Item (4) says Table 2 applies to hybrid facilities with no wind. IEEE 2800-2022 clarifies that it does not apply to synchronous components of hybrid plants. PRC-029-1 needs to be more careful in its wording regarding hybrid plants.

Item (6) of Attachment 1 defines the applicable voltage as the high-side of the MPT and does not give the PC/TP/TO/etc. any flexibility to change that. Some entities with IEEE 2800-2022 requirements have adjusted the Reference Point of Applicability for Ride-through to the POI for various reasons (including that they may install monitoring equipment at that location rather than at the MPT). PRC-029-1 should not remove the flexibility of PC/TP/TO/etc. to alter the point of applicability.

Figure 1 of Attachment 1 uses the old "No-Trip Zone" label which is not used anywhere else in PRC-029-1.

Attachment 2

Regarding Table 3 of Attachment 2, "May trip" on rows 1 and 9 should be replaced with "N/A" for consistency with Table 1 and Table 2. It is unclear why the frequency values are unaligned (and exceed) IEEE 2800-2022 when the voltage Ride-through requirements of PRC-029-1 are aligned with IEEE 2800-2022. It is not prudent to exceed the requirements of IEEE 2800-2022 when 1) it already significantly exceeds PRC-024-3, and 2) it is recognized as an industry standard for utilities, developers, OEMs, etc.

Rows 5 and 6 of Table 3 have incorrect operators and row 6 includes an incorrect number (58.8 instead of 58.5).

Finally, item (1) of Attachment 2 defines the applicable frequency at the high-side of the MPT and does not give the PC/TP/TO/etc. any flexibility to change that. As noted above, some entities with IEEE 2800-2022 based requirements use the POI as the RPA for Ride-through capability.

Response

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project Name:	2020-02 Modifications to PRC-024 (Generator Ride-through) | Draft 2
Comment Period Start Date:	6/18/2024
Comment Period End Date:	7/8/2024
Associated Ballot(s):	2020-02 Modifications to PRC-024 (Generator Ride-through) Implementation Plan AB 2 OT

There were 63 sets of responses, including comments from approximately 138 different people from approximately 91 companies representing 7 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, contact Manager of Standards Information, Nasheema Santos (via email) or at (404) 446-2564.

Questions

1. Provide any comments for the drafting team to consider, if desired.

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities- Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
California ISO	Darcy O'Connell	2	WECC	ISO/RTO Council (IRC) Standards	Ali Miremadi	California ISO	2	WECC
					Gregory Campoli	New York Independent	2	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
				Review Committee		System Operator		
					John Pearson	ISO New England, Inc.	2	NPCC
					Helen Lainis	Independent Electricity System Operator	2	NPCC
					Elizabeth Davis	PJM Interconnection	2	RF
					Charles Yeung	Southwest Power Pool, Inc.	2	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Austin Energy	Michael Dillard	5		Austin Energy	Michael Dillard	Austin Energy	5	Texas RE
					Lovita Griffin	Austin Energy	3	Texas RE
					Tony Hua	Austin Energy	4	Texas RE
					Imane Mrini	Austin Energy	6	Texas RE
					Thomas Standifur	Austin Energy	1	Texas RE
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern	5	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Company Generation		
DTE Energy	Patricia Ireland	4		DTE Energy	Patricia Ireland	DTE Energy - Detroit Edison	4	RF
					Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison Company	5	RF
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Micah Runner	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Gary Dollins	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Olivia Olson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	SERC
					Heath Henry	NW Electric Power Cooperative, Inc.	3	SERC
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	KAMO Electric Cooperative	1	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Brett Douglas	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Mark Riley	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Chuck Booth	Associated Electric Cooperative, Inc.	5	SERC
					Jarrod Murdaugh	Sho-Me Power Electric Cooperative	3	SERC

1. *Provide any comments for the drafting team to consider, if desired*.
Thomas Foltz - AEP - 5

Answer	
Document Name	

Comment

The R1, R2, and R3 design requirement is problematic because of at least two major issues: dynamic modeling deficiencies and lack of standardized test procedures. IBR dynamic modeling is well proven to be deficient in representing performance of equipment in the field, particularly disturbance ride-through performance, and even though MOD-026-2 is addressing model verification/validation, it is still only post-interconnection (or post-commissioning). What is needed here is to expand the scope of MOD-026-2 to also encompass pre-interconnection model verification/validation so that “simulations” and “studies” on IBR plant models evaluating the plant designs are performed on verified and validated dynamic models ahead of interconnection. Secondly, without well-defined, standardized test procedures to assess ride-through capability, there is little possibility that simulations and studies on IBR designs will result in uniform across-the-board assurance that IBR equipment and plant designs adequately adhere to the PRC-029 ride-through requirements. Completion of IEEE 2800.2, which is intended to define the necessary testing and verification procedures, and selective consideration and use of its content in PRC-029 is necessary just as 2800 itself has been instrumental in formulating the mandatory ride-through requirements in PRC-029. Without dynamic model verification/validation and well-defined, standardized test procedures, the design components of R1, R2, and R3 will not achieve the desired outcome and will only result in confusion as to what evidence is actually required from GOs and TOs.

Need to indicate in association with R1 third bullet that momentary current blocking is an acceptable means of reacting to non-fault initiated phase jumps greater than 25 degrees.

There is inconsistency throughout the document in instances of both “TO and GO” and “TO or GO”. Please resolve the inconsistencies.

Please clarify what “other evidence” in M1, M2, and M3 would be acceptable to assure compliance. Please also reinsert “shall” in M1, M2, and M3 where it has been removed (to read “Each GO and TO shall have evidence…”). The sentences are not complete without it and measures in other standards (such as PRC-024-4) read that way.

Figures 1 and 2 in Attachment 1 should be better aligned. One has a log scale on the horizontal axis and the other is linear. There is no valid reason for these differences, and we recommend they be consistent in the axes used. The only difference between them should be the slight difference in the lower boundary of the must ride-through zone reflecting the slight difference between Attachment 1 tables 1 and 2.

There needs to be an exemption for system-related causes of ride-through failure. IBRs should be exempt from ride-through requirements in R1 through R3 if tripping or failure to ride through is attributable to any of the following:

1. Sub-synchronous control interaction or ferro-resonance involving series compensation confirmed by the TOP, RC, TP, or PC

2. Unstable behavior of other nearby IBRs or dynamic devices such as FACTS or HVDC confirmed by the TOP, RC, TP, or PC

3. System short circuit levels during contingencies below the level of IBR stable operation confirmed by the TOP, RC, TP, or PC

4. System-level transient or oscillatory instabilities confirmed by the TOP, RC, TP, or PC

R 2.1.3 should be .95 per unit (with a decimal point) rather than 95 per unit.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
Modeling: The team agrees that the other items noted are essential but that those are within the scope of other 901 related projects and not part of PRC-029.
R1: the bullets under R1 are listed as possible exemptions and are not required to be used for any events
TO: Transmission Owner has been removed from PRC-029.
Measures: Measure M1 is written to provide specific evidence to be used as examples. “Other evidence” is included to provide entities additional flexibility in how to comply. The word “shall” has been re-inserted.
Attachment 1: The logarithmic scale has been removed from Figure 1.
R2.1.3: 95 pu has been corrected to 0.95 pu.

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	
Document Name	

Comment

1) Editorial suggestions **BOLD** and ***ITALICS*** for the Measures in below

2) In PRC-029, standard as follows:

4.2 Facilities:

4.2.1. BEPS inverter-based resources(2)

(2)For the purpose of this standard, "inverter-based resources" refers to a collection of individual solar photovoltaic (PV), Type 3 and Type 4 wind turbines, battery energy storage system (BESS), or fuel cells that operate as a single plant/resource. ***In case of offshore wind plants connecting via a dedicated VSC-HVDC, the inverter-based resource includes the VSC-HVDC system.***

Question for SDT: *Should VSC_HVDC be included even if it's not associated with a windplant (ie Transbay Cable HVDC)?*

M1. Is very clunky, below is my attempt to making it read better.

1}· Replace *have* with *has*.

2}· Reword per the following:

o ***Has*** evidence of dynamic simulations, studies, or other evidence to demonstrate the design of each facility will adhere to Ride-through requirements, as specified in Requirement R1. ***As system conditions allow*** each Generator Owner and Transmission Owner ***retain*** evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) recorded to demonstrate that the operation of each facility did adhere to Ride-through requirements, as specified in Requirement R1. If the Generator Owner and Transmission Owner choose to utilize Ride-through exemptions that occur within the "must Ride-through zone" and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner and Transmission Owner also ***retain*** evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate that the facility failed to Ride-through during a phase jump of greater than or equal to 25 electrical degrees, and documentation from their Transmission Planner, Reliability Coordinator, Planning Coordinator, or Transmission Operator that a non-fault initiated switching event occurred.

M2 .

Each Generator Owner and Transmission Owner ***has*** evidence of dynamic simulations, studies, or other evidence to demonstrate the design of each facility will adhere to requirements, as specified in Requirement R2. Each Generator Owner and Transmission Owner also ***retain*** evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data demonstrating that the operation of each facility did adhere to performance requirements, as specified in Requirement R2, during each voltage excursion measured at the high-side of the main power transformer. ***The Generator Owner or Transmission Owner have evidence of receiving such performance requirements, (e.g. email***

exchange, contract information) if the Transmission Planner, Transmission Operator, Reliability Coordinator, Planning Coordinator has required the Generator Owner or Transmission Owner to follow performance requirements other than those in Requirement R2 (e.g. ramp rates, reactive power prioritization). ***3) Question for SDT: What does this mean?* M3 Same comments as M2.** 4) Figure -1 "*Voltage ride-through requirement for AC-connected wind"* on page 20 does not match Attachment 1 Table-1 on page16 for the requirement of <1.2 and > 1.1 minimum ride-through time of 1 second. 5) For PRC-029-1, section B (Requirements and Measures)- R2- Section 2.2: In section 2.2, footnote 6: mentions that "*In either case and if required, the magnitude of active power and reactive current shall be as specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator*." Question/comment for SDT: It has not been mentioned how to identify the magnitude of active power and reactive current, and it seems that Electromagnetic Transient (EMT) studies should be performed to evaluate each IBR and it will result in a significant amount of extra work for PTO to receive, evaluate and perform EMT studies.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. **2**. The team has removed this footnote and hase been advised to refer to the newly proposed definition for IBR. IBR will include the equipment in this linkage if it is a dedicated connection to the system. Other VSC-HVDC are not included. **Measures**. The team has reinserted the word "shall" into the measures; this is shown as "shall have". The team also agrees that usage of "retain" is preferable language and have made this change to all measures. **3.** The language related to having evidence of other performance requirements was considered necessary for a situation where an entity receives requirements from a planner or operator that would contradict PRC-029 requirements. The team included this as a means of allowing the GO to follow requirements as needed by planners/operators and not be in violation of PRC-029 requirements. **4**. Thank you for the concern, the figure 1 has been updated to reflect these changes. **5**. This work is only required if the established and active power and reactive power does not meet the system requirement. The level of work required depends on the system needs. The level of detail in the study should be part of the decision decided by the applicable RC or TP as needed.
Ijad Dewan - Ijad Dewan On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Ijad Dewan

Answer	
Document Name	
Comment	
The Technical Rationale must include reasons for inclusion of Synchronous Condenser to the standard under the applicability section.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. A conforming change has been made in the updated Technical Rationale and is consistent with the assigned SAR scope.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	
Dominion Energy supports EEI's additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the response, please see the response to EEI's comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	

FirstEnergy requests the DT consider changing PRC-029-1 Requirement 2 R2.5 from active power to apparent.

Entities may incorporate solar sites that automatically change reactive power to attempt to control voltage similar to FirstEnergy's sites. This change will inevitably cause changes in active power post event, such that meeting this requirement as written could be difficult. Since changes in reactive power are desired for voltage control, the requirement should be changed to allow this response. Using apparent power in the requirement versus active power is one way to achieve this.

Likes 0	
Dislikes 0	

Response

Thank you for the comment.
Apparent power: the team determined no changes were needed as this requirement subpart is focused on active power restoration.
Requirement R2.5 requires that active power return to the pre-disturbance level when voltage recovers to the continuous operating region, unless otherwise specified by the TP, PC, RC.

Brian Lindsey - Entergy - 1

Answer	
Document Name	

Comment

- M1: This seems more like a requirement than a measure for meeting the requirement.
- R2, M2, M3 and R4: Duplicative of Mod-026 and MOD-027. Also, seems to be dependent on PRC-028 passing and sites having DDRs installed.
- R2: is not clear. It seems to overlap significantly with VAR-002.
    - Should that be .95 per unit?
- R3: No provisions for exemptions for frequency limitations.
- R4.1 thru 4.2: Are we seeking approval from this large list of entities for an exemption or are we documenting the limitation that prevents from meeting requirement 1? If we have to get approval there is no requirement in this standard that require any of these entities to provide that approval.

- Recommend limiting who must be notified to just the TP or TP and RC. There needs to be a single point of contact instead multiple entities.

Likes 0	
Dislikes 0	

Response

Thank you for the comments.
Measure M1: M1 is written to provide specific evidence to be used as examples.
Implementation Plan: The Implementation Plan has been modified to include bifurcated implementation information between capability-based elements and performance-based elements. This is a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time.
Modeling: The team agrees that the other items noted are essential but that those are within the scope of other 901 related projects and not part of PRC-029
R2: The team identifies VAR-002 as concerned with voltage set points and bandwidths, and is not specific to disturbance Ride-Through, while Requirement R2 is concerned with an IBR riding through a disturbance. The team identifies no overlap because the scopes are different for each requirement.
R2: Agree that the per unit should be 0.95 and not 95.
R3: The exemptions allowable within Order No. 901 are only for some voltage requirements.
R4: Requirement R4 has been modified and footnote added to R4 to clarify acceptance by the CEA. Acceptance by the other entities listed is not required.

Mark Flanary - Midwest Reliability Organization - 10

Answer	
Document Name	

Comment

The draft PRC-029-1 includes expectations in R1, R2, and R3 for entities to demonstrate ride-through adherence (R1 & R3) and performance (R2) through two separate means: 1) dynamics simulations/studies and 2) data from actual system events. These two separate expectations are combined in each requirement but are not clearly delineated within the requirement text. It is only in the measures associated with each requirement that it becomes clear that both expectations exist. This lack of clarity leads to concerns about the auditability of this standard.

The Standard should clearly specify during which timeframes and under what conditions an entity is expected to show compliance using simulations/studies vs. data from actual events. For instance, upon commissioning of a new facility, no event data will be available. Should the CEA

expect to see a study completed for a new facility prior to commercial operation? For existing facilities with extensive recorded event data is it still necessary to perform simulations and studies to show compliance? How much event data and how serious must the events be for this to be acceptable?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Implementation Plan**: The team agrees that additional clarity was needed for the measurability of these requirements. As such, the implementation plan includes bifurcated implementation information between capability-based elements and performance-based elements. This is a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. **Data retention**: disturbances identified by planners and operators within PRC-030 would trigger the request to hold data for demonstrating performance. Additional data requirements are established within PRC-030	
Chantal Mazza - Hydro-Quebec (HQ) - 1 - NPCC	
Answer	
Document Name	
Comment	
It is imperative that the standard drafting teams for this project as well as the 2021-04 (PRC-002 and PRC-028) and 2023-02 (PRC-030 vs PRC-004) assure a coherent way of addressing the inclusion and exclusion of IBRs in current and upcoming standards. The following comments are applicable to PRC-029-1 The definition for Inverter Based Resource (IBR) was approved by industry in April under Project 2020-06. We do not agree with inserting the uncapitalized version of IBR into 4.2 Facilities section because it is unbounded and insufficient to identify the Facilities applicable to this Standard, as required in the Rules of Procedure (Appendix 3a, Standard Processes Manual). Furthermore, these definitions are the foundation of several ongoing projects in response to FERC Order 901, where FERC “directs NERC to submit new or modified Reliability Standards that address specific matters pertaining to the impacts of IBRs on the reliable operation of the BPS.” Chapter A, -Section 4.2.2 What is the “IBR registration criteria”? Please add a footnote to describe it. Requirement R1: 25degrees, 1.1pu-45s and 1.18pu-2s should be moved to attachment 1 to allow for regional variance.	

Requirement -R2-2.1.3 and B-R2-2.2 Can the TP ask for a mix of active/reactive power based on a predetermined ratio (currently only indicated as active OR reactive). Requirement -R3: No exemption exists for existing equipment limitation to meet frequency and ROCOF ride-through? (like R4 for voltage) One should be added. Requirement -R3. The 5Hz/s value should be moved to Attachment 2 to allow for a regional variance. Requirement -R3 The 5Hz/s requirement is already indicated in R1. It should not be repeated. Requirement -R4: Are the phase shift and V/Hz requirements described in R1 considered as being part of the “voltage ride-through criteria”? (or is it for amplitude only) An exemption should be provided for existing equipment with limitations. Requirement -R4 and M4 What should be done when the manufacturer does not exist anymore or refuses to collaborate? Attachment 1: Please explain (footnote) why the ride through requirement for a type-4 wind turbine needs to be different of a PV plant. The Technical Rationale must include reasons for inclusion of Synchronous Condenser to the standard under the applicability section. The term “active power” is not defined and appears to be used in conjunction with Real Power. Recommend consistency throughout the standards when using Real Power vs active power, such as MOD-025, BAL-001, and many others. Recommend the DT reevaluate the implementation period of 6 months. Recommend making implementation period 18 months or greater to account for the need for working with OEMs to implement any setting changes and the need for IBR settings reviews conducted by third parties, as necessary.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. **IBR Definitions**: While the definition for IBR was approved, it included the term IBR Unit, which was not approved and did not have an acceptable resolution to industry and the team. As such the language was considered to be unenforceable. The teams were advised to remove usage of unapproved terms until a clear path forward with the definitions could be assured. Project 2020-06 is moving forward with another version of a definition of IBR that removes the embedded usage of another term. The next drafts of Milestone 2 related projects, including PRC-029, will include this new term as proposed by 2020-06. Additional definitions for parts within an IBR plant/facility will be developed by projects associated with Milestone 3 as determined by those teams.

Applicability for Sub-BES IBR: This section has been modified to include the registration criteria within the recently approved changes to the NERC Rules of Procedures. The team was advised to hold on usage of specific language until the changes had been approved.
R1 and regional variants: Regional variants are allowable and should be initiated through that process of Standards Development. Those variations may be in requirements or the attachments.
R2: The entities listed may specify active and reactive as needed. The "or" is one or both.
R3 exceptions: Exceptions for Provincial authorities are allowable under footnote 12 ("The exemption requests for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction")
R3/R1: The 5Hz/s rocof is only listed in R3.
R1: the bullets under R1 are listed as possible exemptions and are not required to be used for any events.
R4: individual facts and circumstances may be the basis for determination of compliance and are deferred to the Regional Entity.
Attachment 1 wind: This difference is based on the existing auxiliary limitation of type 4 wind to ride-through the same capability of PV. This also aligns with IEEE 2800.
Synchronous condensers prc-024: A conforming change has been made in the updated Technical Rationale and is consistent with the SAR.
Active Power: The terms have been replaced with those from the glossary.
Implementation Plan: The Implementation Plan has been modified to include bifurcated implementation information between capability-based elements and performance-based elements. Essentially this is a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	
Document Name	

Comment

Tri-State has no additional comments for PRC-024-4

Tri-State agrees with MRO NSRF Comments regarding PRC-029-1

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

- The team agrees and has consolidated bullets 1 and 4.

- The team believes that the reference to bullet #4 (previously bullet #5) is helpful to eliminate confusion. - The hyphen has been included in the TR.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	

• PRC-029-1 Attachment 1
  ○ Footnotes 10 and bullet 1 seem redundant. Consider consolidation with bullet 4.
  ○ Footnotes 11, 13 and bullet 5 seem redundant. Consider consolidation.
• Technical Rational for Reliability Standard PRC-029-1
  ○ Requirement R1, paragraph 5 – missing hyphen in “IEEE 2800-2022”.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. - The team agrees and has consolidated bullets 1 and 4. - The team believes that the reference to bullet #4 (previously bullet #5) is helpful to eliminate confusion. - The hyphen has been included in the TR.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
PRC-024: Black Hills Corporation does not have any further comments for this revision for this standard as part of this project. PRC-029: Black Hills Corporation agrees with the comments identified by the NAGF. They are as follows: *The NAGF believes that PRC-029 should allow for frequency ride through (“FRT”) exemptions similar to its treatment of voltage ride through (“VRT”) exemptions. The justification for allowing VRT exemptions in FERC Order 901 also apply to FRT. We believe the statement in FERC Order 901,*	

paragraph 193 in response to ACP/SEIA's comment in paragraph 188 does not preclude the standard drafting team from considering FRT exemptions due legacy equipment limitations. Here are a few reasons why:

1. If FERC's intent was to exclude Frequency Ride Through exemptions while allowing Voltage ride through exemptions, there would be more of a record established to support this differential treatment.

2. FERC responded to ACP/SEIA's comment on ride-through requirements as if they were only asking about voltage ride through requirements. FERC made no mention of frequency ride through requirements.

3. Similar to FERC's rational for the consideration of voltage ride through exemptions, there are also older IBR technologies with hardware that would need to be physically replaced to meet frequency ride through requirements as well.

4. NERC and the NERC Standard Drafting Teams have the technical expertise to address complex technical issues such as legacy equipment limitations that FERC does not have.

Applicability Section, 4.2.2 – Recommend removing this section.

Requirement R1: The NAGF notes that R1 only addresses voltage ride through and should be revised to include frequency ride through as well. In addition, R1 should address frequency ride through limitations for legacy IBR facilities.

Measurement M1 – The proposed narrative reads more like requirements than measures; recommend to revise the narrative accordingly. In addition, the NAGF notes that the proposed narrative seems to assume that PRC-028 will be need to be approved/in place for PRC-029 to be a viable standard.

Requirement 2.1.3: The narrative is unclear as to what is expected for this proposed requirement. Request that the narrative be rewritten/restructured to address this issue. In addition, it is unclear which entity will define the preference for active or reactive power. The NAGF suggests that the Transmission Planner (TP) should have the authority to define this preference. This recommendation also applies to Requirement 2, second bullet and Footnote 6.

Requirement R2.5: The NAGF recommends that the narrative be revised to state that active power shall be restored when" the voltage at the high-side of the main power transformer returns to the Continuous Operating Region".

Requirement R4: The draft narrative does not clearly specify who is responsible for approving the exemption. The NAGF requests the narrative be revised to address this issue.

Measure M4: Recommend replacing the word "seeking: with "submitting" in the first sentence.

Additionally, Black Hills Corporation reviewed and agrees with EEI's high level concerns for PRC-029, which are:

1. The Standard attempts to redefine the approved definition of IBR by adding VSC-HVDC systems after the IBR definition was approved by the industry.

2. The Standard adds TOs to this Standard solely to address VSC-HVDC systems, yet no technical justification has been provided. Moreover, these systems were not identified in FERC Order No. 901, or this SAR and they were not clearly identified in the Applicability Section of this proposed Reliability Standard.

3. EEI is concerned with the inclusion of requirements that are not clearly defined or set by multiple registered entities (i.e., TP, PC, RC, or TOP). This creates regulatory confusion and places IBR-GOs in a position where they may need to comply with any number of entities without clearly defining who is responsible. (See Requirement R2, subpart 2.1.3; subpart 2.2 (bullet 2); subpart 2.5) Moreover, the identification of multiple entities who could be responsible creates a situation where IBR-GOs will have reporting obligations to multiple entities because no single entity is identified as being responsible. (See requirement R4, subparts 4.2 & 4.2.1; subpart 4.3) We further note that none of the entities identified (i.e., TP, PC, RC, or TOP) are identified within the Applicability section of this proposed Reliability Standard. All of this can create confusion and places considerable burden on the IBR-GOs that needs to be resolved and clarified.

4. Throughout this Reliability Standard there is use of non-glossary terms (i.e., active power vs. Real Power) where glossary terms are available and should be used. While in other cases glossary terms are used but not capitalized. (e.g., reactive power vs. Reactive Power) Greater efforts should be made to use NERC Glossary terms where appropriate and capitalize those terms, as required.

Detailed Concerns

Ride-through Definition Comments: EEI does not support the proposed definition for “Ride-through” as proposed because it is too vague and contains no defined limits, as proposed. We recommend the following changes:

Ride-through: Ability to withstand voltage or frequency Disturbances within defined regulatory limits remaining connected, synchronized with the Transmission System, and continuing to operate**.** *(remove:* ***in response to System conditions through the time-frame of a System Disturbance.****)*

Applicability Section Comments:

Footnote 1: EEI does not support adding TO that own VSC-HVDC systems because this was not a scope item and is therefore not be included in the scope of this SAR. Moreover, Footnote 1 conflicts with Footnote 2 which defines VSC-HVDC as an IBR, which is again does not in alignment with the approved definition of an IBR.

Footnote 2: EEI does not support Footnote 2 because it expands the definition of IBRs beyond what was recently approved by the industry, noting the expansion of IBRs to include VSC-HVDC. Furthermore, there was no technical justification for adding VSC-HVDC and the SAR did not include adding VSC-HVDC systems to this project. For this reason, we ask that the definition of IBR not be expanded through footnotes and suggest that the DT submit a technical justification for adding VSC-HVDC systems to the applicability section of this Standard, rather than redefining an approved definition in a footnote.

To address our concerns related to Footnotes 1 & 2 we suggest that if VSC-HVDC systems are to be classified as IBRs, then the approved definition should be pulled by NERC and resubmitted with those resources added to the definition and resubmitted to the industry for approval. Alternatively, VSC-HVDC systems could be defined separately, and that definition submitted to the industry for approval. In both cases, a technical justification should be provided to the industry that defines the issues and risks to BPS reliability that VSC-HVDC systems pose

EEI suggests that if the DT believes that certain IBR capabilities as identified under Requirement R2 need (or may need) to be specified then they should identify the entity who should be responsible among the four identified (i.e., TP, PC, RC or TOP); add them to the applicability section of this Reliability Standard; add clear requirements and adjust the reporting obligations for the IBR-GO under Requirement R4.

Requirement R1 & R2 Comments: EEI does not agree with the inclusion of Transmission Owners because they would only have an obligation under this Reliability Standard if VSC-HVDC systems were included. Given we do not support the inclusion of VSC-HVDC systems without a technical justification and modified SAR, we ask that Transmission Owners be removed from Requirement R1.

Measures M1 & M2: EEI is concerned that M1 & M2 contains measures that are overly prescriptive providing little discretion to IBR-GOs in demonstrating their compliance with Requirements R1 and R2 that seem to align more with a Requirement than a Measure. To address our concerns, we offer the following suggested changes to M1 and suggest similar changes be made to M2:

M1. Each Generator Owner (*remove:* ***and Transmission Owner***) **shall** have evidence (*remove:* ***of dynamic simulations, studies, or other evidence to demonstrate the design of each facility will adhere***) **that supports the** Ride-through **capability of each of their facilities**, as specified in Requirement R1. (e.g., simulations, studies, recorded data from disturbance monitoring equipment, etc.) (*remove:* ***Each Generator Owner and Transmission Owner have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) to demonstrate that the operation of each facility did adhere to Ride-through requirements, as specified in Requirement R1.***) If the Generator Owner and Transmission Owner choose to utilize Ride-through exemptions that occur within the "must Ride-through zone" and are caused by non-fault-initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner (*remove:* ***and Transmission Owner***) also have evidence **supporting that exemption. (e.g., studies, simulations or supporting data from disturbance monitoring equipment)** (*remove:* ***of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate that the facility failed to Ride-through during a phase jump of greater than or equal to 25 electrical degrees, and documentation from their Transmission Planner, Reliability Coordinator, Planning Coordinator, or Transmission Operator that a non-fault initiated switching event occurred***).

Requirement R3 & R4: EEI does not support the inclusion of Transmission Owners within Requirements R3 & R4 for the same reasons identified above.

Likes 0	

Dislikes 0	

Response

Thank you for your comments.
Frequency Exemptions: The team has been advised by NERC that only including some voltage-based exemptions were intended with the language of the Order and this was confirmed.
Applicability Section – This section has been modified to reflect the current IBR definition as well as the approved changes to registration within the NERC Rules of Procedure. These modifications are consistent with changes to the applicability section within PRC-028 and PRC-030.
R1: R1 only covers voltage requirements and R3 is for the frequency requirements. The structure of PRC-029 and allowable exemptions will not work to combine these two.
Measures: the measures are written to provide specific examples of evidence needed for compliance. Further the implementation plan has been revised to bifurcate between capability-based elements and performance-based elements. Essentially this is now a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. This will allow entities to align their PRC-028 and the performance-based aspects for PRC-029 compliance.
R2.1.3: For Requirement R 2.1.3, revisions have been made clarify the requirement.
R2.5: Requirement R2.5 requires that active power return to the pre-disturbance level when voltage recovers to the continuous operating region, unless otherwise specified by the TP,PC, RC.
R4: Modifications to R4 have been made to clarify that the GO will submit the information to the CEA for "acceptance". Additionally, a footnote has been added to clarify this "acceptance".
M4. The modification was made to change "seeking" to "submitting"
IBR Definitions: While the definition for IBR was approved, it included the term IBR Unit, which was not approved and did not have an acceptable resolution to industry and the team. As such the language was considered to be unenforceable. The teams were advised to remove usage of unapproved terms until a clear path forward with the definitions could be assured. Project 2020-06 is moving forward with another version of a definition of IBR that removes the embedded usage of another term. The next drafts of Milestone 2 related projects, including PRC-029, will include this new term as proposed by 2020-06. Additional definitions for parts within an IBR plant/facility will be developed by projects associated with Milestone 3 as determined by those teams. Further**,** regarding sub-BES IBR: the applicability section has been modified to include the registration criteria within the recently approved changes to the NERC Rules of Procedures. The team was advised to hold on usage of specific language until the changes had been approved.
Transmission Owner: The transmission owner has been removed from PRC-029.
Other Performance Requirements: The language related to having evidence of other performance requirements was considered necessary for a situation where an entity receives requirements from a planner or operator that would contradict PRC-029 requirements. The team included this as a means of allowing the GO to follow requirements if needed by planners/operators and not be in violation of PRC-029 requirements. Planners and operators are not required to provide other performance requirements and are not applicable to this Standard.
Active Power: The terms have been replaced with those from the glossary.
Ride-through definition: The definition for Ride-through has been revised.

Applicability: As a follow up to the response for **Transmission Owner** and **Other Performance Requirements**, the team identifies no obligation or requirement for entities, other than the GO, for any requirements in PRC-029.
Measures: The measures are written to provide specific examples of evidence needed for compliance. PRC-029 cannot have performance measurements of actual data removed as that has been directed. The implementation plan has been bifurcated between capability-based and performance-based requirements to allow entities additional time to align PRC-028 and PRC-029 implementation

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	

Comment

PRC-024-4

No Comments, MH is generally supportive of this proposed standard.

PRC-029-1

Applicability:

The standard switches between BPS (bulk power system) and BES (bulk electric system). For consistency, one term should be used throughout the standard.

R1: bullet # 3:

MH recommends adding a footnote stating that the facility may operate in current block mode if necessary to avoid tripping for non-fault initiated phase jumps greater than 25 degrees.

R2:

MH recommends that the defined terms, Real Power and Reactive Power be used throughout the document instead of active power and reactive power.

R 2.1.3

To SDT: “The voltage is below 95 per unit” should be replaced by “The voltage is below 0.95 per unit”

R 2.1.3 & 2.2

Allowing multiple entities to place potentially conflicting requirements upon an applicable functional entity is unacceptable. Either a single entity be tasked with the obligation, or a hierarchy be provided so that an entity is not placed in a multibed conflicted request situation.

M1, M2, M3, and R4

To SDT: Consistently replace “Each Generator Owner and Transmission Owner” with “Each Generator Owner or Transmission Owner”

R3

This requirement requires that Each Generator Owner or Transmission Owner shall ensure the design and operation are such that each facility adheres to Ride-through requirements during a frequency excursion but does not require any governor response action or capability. The inverter-based resources that “adhere to Ride-through requirements” but are not based on frequency deviation, would comply with the standard requirements, which is not ideal. The TP/PC is expected to specify inverter-based resources performance during abnormal system frequency.

MH recommends:

Each Generator Owner or Transmission Owner shall ensure the design and operation is such that each facility adheres to Ride-through requirements **and response as specified by TP, RC, TOP, or PC** during a frequency excursion.

Implementation plan:

The standard is event-based compliance that requires installing recorded equipment data with higher sampling rates at all applicable legacy IBR Facilities. Therefore, we suggest that the implementation plan for PRC-029 should be aligned with Project 2021-04 (PRC-028-1) for the legacy IBRs. Also, MH recommends that the implementation plan of legacy IBR (a facility that is in service by the effective date of PRC-029-1) be longer than any new interconnected IBR (a facility that is in service after the effective date of PRC-029-1/ PRC-028-1)

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
Terminology: The BPS/BES terminology has been resolved.
R1: R1 bullet 3: The team agrees and has added this footnote.
Active Power: The terms have been replaced with those from the glossary.
Per Unit errata: 95 pu has been changed to 0.95 per unit

Other Performance Requirements: The team intends the language for GOs who receive requirements from planner/operators that conflict with PRC-029, that those entities would not be in violation of either. The team will include additional language within the technical rationale in regards to if there are conflicting requirements issued to the GO by planner/operators.
Transmission Owner: The team has removed Transmission Owner from PRC-029
R3: governor response is not in scope for this project.
Implementation Plan: The Implementation Plan has been modified to include bifurcated implementation information between capability-based elements and performance-based elements. Essentially this is a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. This approach allow allows for entities to align their PRC-028 and the performance-based aspects of their PRC-029 implementation

Kimberly Turco - Constellation - 6	
Answer	
Document Name	

Comment

Constellation feels that the draft 2 added significant technical requirements that would require OEM collaboration and input on their equipment. Operating at Max capability requires additional analysis from GOs and OEMs to ensure subcomponents in the BOP and WTG side will be able to operate at these limits.

Further, the added language for the high side transformer volts per hz (Hz) settings to exceed 1.1 per unit longer than 45 seconds or exceed 1.18 for longer than 2 seconds will require GO/GOPs to work with the transformer manufacturer to see if these new limits can be met. The volt/hz settings are set to protect the transformer during over excitation conditions and they are above the provided transformer excitation curve from the manufacturer.

Also, the new ride through voltage limits is set so high that the current WTGs will not be able to ride through without tripping due to equipment operating conditions. OEMs are still unsure and not incentivized to collaborate in a timely manner to understand capabilities and limitations.

Finally, Constellation asks the DT to address scheduling and implementation plan. The current plan is not reasonable to implement.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

Capability: The IBR current capability is different than the current limit. What is required is to operate to the designed current specification including rated and the short-term overcurrent rating.
Volts per hz: R1 bullet 4 is also an exemption and not a requirement.
Voltage limits: if there are any equipment limitations for voltage, then R4 is intended to address such a hardware-based limitation for legacy IBR.
Implementation Plan: The Implementation Plan has been modified to include bifurcated implementation information between capability-based elements and performance-based elements. Essentially this is a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. This approach allows for entities to align their PRC-028 and the performance-based aspects of their PRC-029 implementation.

Alison MacKellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation feels that the draft 2 added significant technical requirements that would require OEM collaboration and input on their equipment. Operating at Max capability requires additional analysis from GOs and OEMs to ensure subcomponents in the BOP and WTG side will be able to operate at these limits.

Further, the added language for the high side transformer volts per hz (Hz) settings to exceed 1.1 per unit longer than 45 seconds or exceed 1.18 for longer than 2 seconds will require GO/GOPs to work with the transformer manufacturer to see if these new limits can be met. The volt/hz settings are set to protect the transformer during over excitation conditions and they are above the provided transformer excitation curve from the manufacturer.

Also, the new ride through voltage limits is set so high that the current WTGs will not be able to ride through without tripping due to equipment operating conditions. OEMs are still unsure and not incentivized to collaborate in a timely manner to understand capabilities and limitations.

Finally, Constellation asks the DT to address scheduling and implementation plan. The current plan is not reasonable to implement.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

Capability: The IBR current capability is different than the current limit. What is required is to operate to the designed current specification including rated and the short-term overcurrent rating. **Volts per hz**: R1 bullet 4 is also an exemption and not a requirement. **Voltage limits**: if there are any equipment limitations for voltage, then R4 is intended to address such a hardware-based limitation for legacy IBR. **Implementation Plan**: The Implementation Plan has been modified to include bifurcated implementation information between capability-based elements and performance-based elements. Essentially this is a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. This approach allows for entities to align their PRC-028 and the performance-based aspects of their PRC-029 implementation.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	
Document Name	
Comment	

AZPS supports the following comments that were submitted by EEI on behalf of its members:

PRC-029-1 Comments:

While EEI appreciates that changes made to address our previous comments for the 1st draft of PRC-029-1, we have some new concerns that need to be addressed.

Our high level concerns are described in our comments below:

1. The Standard attempts to redefine the approved definition of IBR by adding VSC-HVDC systems after the IBR definition was approved by the industry.

2. The Standard adds TOs to this Standard solely to address VSC-HVDC systems, yet no technical justification has been provided. Moreover, these systems were not identified in FERC Order No. 901, or this SAR and they were not clearly identified in the Applicability Section of this proposed Reliability Standard.

3. EEI is concerned with the inclusion of requirements that are not clearly defined or set by multiple registered entities (i.e., TP, PC, RC, or TOP). This creates regulatory confusion and places IBR-GOs in a position where they may need to comply with any number of entities without clearly defining who is responsible. (See Requirement R2, subpart 2.1.3; subpart 2.2 (bullet 2); subpart 2.5) Moreover, the identification of multiple entities who could be responsible creates a situation where IBR-GOs will have reporting obligations to multiple entities because no single entity is identified as being responsible. (See requirement R4, subparts 4.2 & 4.2.1; subpart 4.3) We further note that none of the entities identified (i.e., TP, PC, RC, or

TOP) are identified within the Applicability section of this proposed Reliability Standard. All of this can create confusion and places considerable burden on the IBR-GOs that needs to be resolved and clarified.

4. Throughout this Reliability Standard there is use of non-glossary terms (i.e., active power vs. Real Power) where glossary terms are available and should be used. While in other cases glossary terms are used but not capitalized. (e.g., reactive power vs. Reactive Power) Greater efforts should be made to use NERC Glossary terms where appropriate and capitalize those terms, as required.

Detailed Concerns

Ride-through Definition Comments:

EEI does not support the proposed definition for "Ride-through" as proposed because it is too vague and contains no defined limits, as proposed. We recommend the following changes:

Ride-through: Ability to withstand voltage or frequency Disturbances within defined regulatory limits remaining connected, synchronized with the Transmission System, and continuing to operate***. in response to System conditions through the time-frame of a System Disturbance(remove).***

Applicability Section Comments:

Footnote 1: EEI does not support adding TO that own VSC-HVDC systems because this was not a scope item and is therefore not be included in the scope of this SAR. Moreover, Footnote 1 conflicts with Footnote 2 which defines VSC-HVDC as an IBR, which is again does not in alignment with the approved definition of an IBR.

Footnote 2: EEI does not support Footnote 2 because it expands the definition of IBRs beyond what was recently approved by the industry, noting the expansion of IBRs to include VSC-HVDC. Furthermore, there was no technical justification for adding VSC-HVDC and the SAR did not include adding VSC-HVDC systems to this project. For this reason, we ask that the definition of IBR not be expanded through footnotes and suggest that the DT submit a technical justification for adding VSC-HVDC systems to the applicability section of this Standard, rather than redefining an approved definition in a footnote.

To address our concerns related to Footnotes 1 & 2 we suggest that if VSC-HVDC systems are to be classified as IBRs, then the approved definition should be pulled by NERC and resubmitted with those resources added to the definition and resubmitted to the industry for approval. Alternatively, VSC-HVDC systems could be defined separately, and that definition submitted to the industry for approval. In both cases, a technical justification should be provided to the industry that defines the issues and risks to BPS reliability that VSC-HVDC systems pose

EEI suggests that if the DT believes that certain IBR capabilities as identified under Requirement R2 need (or may need) to be specified then they should identify the entity who should be responsible among the four identified (i.e., TP, PC, RC or TOP); add them to the applicability section of this Reliability Standard; add clear requirements and adjust the reporting obligations for the IBR-GO under Requirement R4.

Requirement R1 & R2 Comments: EEI does not agree with the inclusion of Transmission Owners because they would only have an obligation under this Reliability Standard if VSC-HVDC systems were included. Given we do not support the inclusion of VSC-HVDC systems without a technical justification and modified SAR, we ask that Transmission Owners be removed from Requirement R1.

Measures M1 & M2: EEI is concerned that M1 & M2 contains measures that are overly prescriptive providing little discretion to IBR-GOs in demonstrating their compliance with Requirements R1 and R2 that seem to align more with a Requirement than a Measure. To address our concerns, we offer the following suggested changes to M1 and suggest similar changes be made to M2:

M1. Each Generator Owner shall have evidence that supports the Ride-through capability of each of their facilities, as specified in Requirement R1. (e.g., simulations, studies, recorded data from disturbance monitoring equipment, etc.) If the Generator Owner and Transmission Owner choose to utilize Ride-through exemptions that occur within the "must Ride-through zone" and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner also have evidence supporting that exemption. (e.g., studies, simulations or supporting data from disturbance monitoring equipment)

Requirement R3 & R4: EEI does not support the inclusion of Transmission Owners within Requirements R3 & R4 for the same reasons identified above.

Likes 0	
Dislikes 0	

Response

IBR Definitions: While the definition for IBR was approved, it included the term IBR Unit, which was not approved and did not have an acceptable resolution to industry and the team. As such the language was considered to be unenforceable. The teams were advised to remove usage of unapproved terms until a clear path forward with the definitions could be assured. Project 2020-06 is moving forward with another version of a definition of IBR that removes the embedded usage of another term. The next drafts of Milestone 2 related projects, including PRC-029, will include this new term as proposed by 2020-06. Additional definitions for parts within an IBR plant/facility will be developed by projects associated with Milestone 3 as determined by those teams. Further**,** regarding sub-BES IBR: the applicability section has been modified to include the registration criteria within the recently approved changes to the NERC Rules of Procedures. The team was advised to hold on usage of specific language until the changes had been approved.
Transmission Owner: The transmission owner has been removed from PRC-029.
Other Performance Requirements: The language related to having evidence of other performance requirements was considered necessary for a situation where an entity receives requirements from a planner or operator that would contradict PRC-029 requirements. The team included this as a means of allowing the GO to follow requirements if needed by planners/operators and not be in violation of PRC-029 requirements. Planners and operators are not required to provide other performance requirements and are not applicable to this Standard.
Active Power: The terms have been replaced with those from the glossary.
Ride-through definition: The definition for Ride-through has been revised.

Applicability: As a follow up to the response for **Transmission Owner** and **Other Performance Requirements**, the team identifies no obligation or requirement for entities, other than the GO, for any requirements in PRC-029.
Measures: The measures are written to provide specific examples of evidence needed for compliance. PRC-029 cannot have performance measurements of actual data removed as that has been directed. The implementation plan has been bifurcated between capability-based and performance-based requirements to allow entities additional time to align PRC-028 and PRC-029 implementation.

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	
Document Name	
Comment	
Vistra supports comments made by EEI and Entergy.	
Likes 0	
Dislikes 0	
Response	
Thank you. Please refer to the responses to EEI and Entergy.	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 1	
Likes 0	
Dislikes 0	
Response	
Thank you. Please refer to the responses to EEI and MRO NSRF.	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
AECI supports comments provided by the NAGF.	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	

PRC-029:

General Comment: The NAGF believes that PRC-029 should allow for frequency ride through ("FRT") exemptions similar to its treatment of voltage ride through ("VRT") exemptions. The justification for allowing VRT exemptions in FERC Order 901 also apply to FRT. We believe the statement in FERC Order 901, paragraph 193 in response to ACP/SEIA's comment in paragraph 188 does not preclude the standard drafting team from considering FRT exemptions due legacy equipment limitations. Here are a few reasons why:

1. If FERC's intent was to exclude Frequency Ride Through exemptions while allowing Voltage ride through exemptions, there would be more of a record established to support this differential treatment.

2. FERC responded to ACP/SEIA's comment on ride-through requirements as if they were only asking about voltage ride through requirements. FERC made no mention of frequency ride through requirements.

3. Similar to FERC's rational for the consideration of voltage ride through exemptions, there are also older IBR technologies with hardware that would need to be physically replaced to meet frequency ride through requirements as well.

4. NERC and the NERC Standard Drafting Teams have the technical expertise to address complex technical issues such as legacy equipment limitations that FERC does not have.

Applicability Section, 4.2.2 – Recommend removing this section.

Requirement R1: The NAGF notes that R1 only addresses voltage ride through and should be revised to include frequency ride through as well. In addition, R1 should address frequency ride through limitations for legacy IBR facilities.

Measurement M1 – The proposed narrative reads more like requirements than measures; recommend to revise the narrative accordingly. In addition, the NAGF notes that the proposed narrative seems to assume that PRC-028 will be need to be approved/in place for PRC-029 to be a viable standard.

Requirement 2.1.3: The narrative is unclear as to what is expected for this proposed requirement. Request that the narrative be rewritten/restructured to address this issue. In addition, it is unclear which entity will define the preference for active or reactive power. The NAGF suggests that the Transmission Planner (TP) should have the authority to define this preference. This recommendation also applies to Requirement 2, second bullet and Footnote 6.

Requirement R2.5: The NAGF recommends that the narrative be revised to state that active power shall be restored when" the voltage at the high-side of the main power transformer returns to the Continuous Operating Region".

Requirement R4: The draft narrative does not clearly specify who is responsible for approving the exemption. The NAGF requests the narrative be revised to address this issue.

Measure M4: Recommend replacing the word "seeking: with "submitting" in the first sentence.

Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	

Response

Thank you for your comments.
Frequency Exemptions: The team has been advised by NERC that only including some voltage-based exemptions were intended with the language of the Order and this was confirmed.
Applicability Section – This section has been modified to reflect the current IBR definition as well as the approved changes to registration within the NERC Rules of Procedure. These modifications are consistent with changes to the applicability section within PRC-028 and PRC-030.
R1: R1 only covers voltage requirements and R3 is for the frequency requirements. The structure of PRC-029 and allowable exemptions will not work to combine these two.
Measures: the measures are written to provide specific examples of evidence needed for compliance. Further the implementation plan has been revised to bifurcate between capability-based elements and performance-based elements. Essentially this is now a phased-in implementation plan

whereas each entity will be required to respond to the full requirement over time. This will allow entities to align their PRC-028 and the performance-based aspects for PRC-029 compliance.
R2.1.3: For Requirement R 2.1.3, revisions have been made clarify the requirement.
R2.5: Requirement R2.5 requires that active power return to the pre-disturbance level when voltage recovers to the continuous operating region, unless otherwise specified by the TP,PC, RC.
R4: Modifications to R4 have been made to clarify that the GO will submit the information to the CEA for "acceptance". Additionally, a footnote has been added to clarify this "acceptance".
M4. The modification was made to change "seeking" to "submitting"

Karen Demos - NextEra Energy - Florida Power and Light Co. - 1,3,6	
Answer	
Document Name	
Comment	
Support NEE comments submitted	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please refer to the response to NEE.	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	
Comment	

PRC-024-4

No Comments, MRO NSRF is generally supportive of this proposed standard.

PRC-029-1

MRO NSRF recommends that the defined terms, Real Power and Reactive Power be used throughout the document instead of active power and reactive power.

Section 4, footnote 2 – MRO NSRF does not support using a definition for “inverter based resources” that differs from the what is currently being proposed by the standard drafting team responsible for developing the Glossary of Terms definition for this term. There must be alignment between standards prior to any of them being able to move forward.

Measure 1 – This measure is overly prescriptive and does not allow the applicable functional entity sufficient flexibility to demonstrate compliance with Requirement 1. MRO NSRF would recommend the standard drafting team review measures from PRC-024 and align with the approach taken there.

Measure 2 – This measure is overly prescriptive and does not allow the applicable functional entity sufficient flexibility to demonstrate compliance with Requirement 2. MRO NSRF would recommend the standard drafting team review measures from PRC-024 and align with the approach taken there.

Requirement 2.1.3 – This requirement is unclear in its intent. Additionally, allowing multiple entities to place potentially conflicting requirements upon an applicable functional entity is unacceptable. Either a single entity be tasked with the obligation, or a hierarchy be provided so that an entity is not placed in a “catch-22” situation.

Requirement 4 – MRO NSRF Recommends the following modifications to improve clarity:

Each Generator Owner and Transmission Owner identifying a facility that is in-service by the effective date of PRC-029-1, that has known hardware limitations which prevent the facility from meeting voltage Ride-through criteria as detailed in Requirements R1 and R2, and requires an exemption from specific voltage Ride-through criteria shall:

Measure 4 – MRO NSRF recommends changing “seeking” to “documenting” or “submitting”.

Additional comments:

1. The standard switches between BPS (bulk power system) and BES (bulk electric system). For consistency, one term should be used throughout the standard.

2. R1 bullet # 3: MRO NSRF recommends adding a footnote stating that the facility may operate in current block mode if necessary to avoid tripping for non-fault initiated phase jumps greater than 25 degrees

3. M1, M2, M3, and R4: consistent replace “Each Generator Owner and Transmission Owner” with “Each Generator Owner or Transmission Owner”

4. R2, 2.1.3: “The voltage is below 95 per unit” should be replaced by “The voltage is below 0.95 per unit”

Likes 1	Lincoln Electric System, 3, Christensen Sam
Dislikes 0	

Response

Thank you for your comments.
Active Power: The terms have been replaced with those from the glossary.
IBR Definitions: While the definition for IBR was approved, it included the term IBR Unit, which was not approved and did not have an acceptable resolution to industry and the team. As such the language was considered to be unenforceable. The teams were advised to remove usage of unapproved terms until a clear path forward with the definitions could be assured. Project 2020-06 is moving forward with another version of a definition of IBR that removes the embedded usage of another term. The next drafts of Milestone 2 related projects, including PRC-029, will include this new term as proposed by 2020-06. Additional definitions for parts within an IBR plant/facility will be developed by projects associated with Milestone 3 as determined by those teams**.**
Measures: The measures are written to provide specific evidence to be used as examples and allow for other evidence for entity-specific flexibility. These measures cannot align with PRC-024 and that standard is focused on equipment settings and PRC-029 must evaluate actual performance.
Other Performance Requirements: The language related to having evidence of other performance requirements was considered necessary for a situation where an entity receives requirements from a planner or operator that would contradict PRC-029 requirements. The team included this as a means of allowing the GO to follow requirements as needed by planners/operators and not be in violation of PRC-029 requirements. Additional language has been added to the technical rationale for clarity.
M4. The modification was made to change “seeking” to “submitting”
Terminology: The BPS/BES terminology has been resolved.
R1: R1 bullet 3: The team agrees and has added this footnote.
Per Unit errata: 95 pu has been changed to 0.95 per unit

Richard Vendetti - NextEra Energy - 5

Answer	
Document Name	

Comment

R1 “The instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer and is initiated by a non-fault switching event on the transmission system” - *How is the GO of IBR going to identify the cause of the fault?*

R1 “The Volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.” – *What is the technical rationale behind the 45 second and 2 seconds? This is a very specific scenario as described in the “Technical Rationale”. Requests incorporating language that suggests where it applies.*

M1 *M1 requires multiple data requirements. It is not clear in language. Interpretation is that GO / TO should have evidence that design can meet as well as performance based evidence that it does or does not perform. The amount and time frame to collect evidence is not provided. Is the expectation that this data is only required for a specific event upon the data request?*

The language in R2 requirements does not explicitly state that changes in resource availability (i.e wind or sun) will also affect the active and reactive current or recovery of the IBR.

R2.5 “Each facility shall restore active power output to the pre-disturbance or available level (whichever is lesser) within 1.0 second when the voltage at the high-side of the main power transformer returns from the mandatory operation region or permissive operation region (including operating in current block mode)” *Recommend language updated to “continuous operating region”. IBR units will be limited in capabilities until transient has ended and IBR equipment is no longer sitting at its equipment limiters”*

It is not understood why requirement R1 exists when R2 has all the details. The standard appears to be first written as the test criteria for model validation. Secondly, as a standard to provide data that plant performance matches model. A standard practice guide on the method to demonstrate compliance through dynamic simulations, studies or other evidence is necessary before full adoption of new standard.

Attachment 1

Overall there are concerns with the PRC-029 implementation timeline for any requirement where the OEM has not had time to fully assess the new requirement and utilize the new IEEE2800 testing standard. New standard implementation needs to give GO/TO time to fully assess new requirements; in particular with the multiple disturbance criteria or method OEMs calculate values.

There is no R6

R3/M3 – All Measurement requirements should be confirmed as inclusion into the PRC-028 standard (RoCoF, V/Hz, Phase Angle, etc)

There is no instruction regarding requirement if IBR cannot meet R3 due to Equipment Limitation

R4 Implementation timeline is too short to assess all facilities with additional requirements in PRC-029. There is also not enough time to allow for OEM responses. Recommend tracking an implementation guideline similar to PRC-028 and PRC-030 to meet FERC deadline.

There is no instruction on process to report a new limitation after the full implementation of R4 when a piece of equipment within the IBR may temporarily limit the capability

R4.3 Each Generator Owner and Transmission Owner with a previously submitted request for exemption that replace the equipment causing the limitation shall document and communicate such an equipment change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the equipment change

The language should be clear to state "full replacement". Should not be misinterpreted to include subcomponent replacement.

There is no R5

The Implementation timeline of this standard is the most concerning given the additional requirements generating new review of all facilities and the need to receive additional feedback from OEMs without new testing standard.

The performance data collection requirements will need to align with implementation timeline of PRC-028 at each facility.

A practice guide is highly recommended to demonstrate method and expectation for compliance.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
R1: The non-fault switching event occurrence is considered a potential exemption for tripping within the must Ride-through zone R1 and is not required. If the exemption must be utilized by the GO, then the required measurement to support the exemption would need to be collected from the RC, TP, or PC.
Volts/Hz: Additional information has been added to the Technical Rationale.
M1/M2: The Implementation Plan has been modified to include bifurcated implementation information between capability-based elements and performance-based elements. Essentially this is a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time.
R2: The team agrees this was intended and has included additional language to clarify changes to fuel sources.
R1/R2: R1 requires ride-through within the must Ride-through zone. R2 includes additional performance requirements beyond tripping/momentary cessation/failing to Ride-through.
R3: The measurement data needed to derive these characteristics are confirmed to be in PRC-028.
R3: Frequency exemptions are not included as allowable exemptions within FERC Order No. 901.
Implementation Plan: The Implementation Plan has been modified to include bifurcated implementation information between capability-based elements and performance-based elements. Essentially this is a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. This approach allows for entities to align their PRC-028 and the performance-based aspects of their PRC-029 implementation.

R4: Temporary capability limitations would be communicated through normal mechanisms (e.g., GADS) and would not qualify as exemptions from Ride-through. **Equipment replacement**: replacement for maintenance in-kind does not remove the limitation. Additional language was added to 4.3.1 to clarify this. **Practice Guides**: Practice Guides are not developed by Drafting Teams.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
Avista supports the development of a new Reliability Standard to address gaps in Inverter-Based Resource Performance but has concerns with numerous definitions/verbiage.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
R1: *Revise text as follows: "…each facility adheres to voltage Ride-through requirements…"* *WEC also disagrees with M1 and agrees with the comments made by NAGF and EEI.* ***R2:*** *WEC disagrees with text "…shall ensure the design and operation is such…". The requirement must state what TO and GO must do. Otherwise, this requirement is open-ended without a measurable statement. The "…shall ensure" has no quantitative meaning and it does not benefit the BES stability.*	

2.1: *The proposed "continuous operating region" range conflicts with acceptable continuous operating ranges by Transmission Operators. Many Transmission Operators classify continuous operating range from 0.95 and 1.05 pu, and consider voltage ranges from 0.9 to 0.95 pu and 1.05 to 1.1 pu as abnormal voltage ranges.*

2.1.1: *Continue to deliver the pre-disturbance level of active power or available active power, whichever is less.* ***Please explain and list what entity must do to ensure this requirement is met.***

2.1.2: *Continue to deliver reactive power up to its reactive power limit and according to its controller settings.* ***Please explain and list what entity must do to ensure this requirement is met.***

2.1.3: *What document governs a TP, PC, RC or TO to specify active/reactive power prioritization.*

2.3: *Term "current block mode" may not be understood and its meaning could be misinterpreted. Does it mean mandatory cessation? Please explain and at least define it in footnotes. Assuming this means momentary cessation, it looks like this requirement will allow momentary cessation if necessary to avoid tripping, OR, per 2.3.1 entity can enter current cessation for 5 cycles. It seems the statement contradicts itself.*

2.5: *WEC owns and operates multiple IBR sites and it is in our experience that the limitation to the one second requirement will come from the power plant controller. The ramp rate capabilities of the power plant controllers are far slower than inverter ramp rates and are typically in minutes range. WEC also had an instance where the power plant controller ramp rate increase was denied by the Transmission Operator/Planner. Applying one second requirement will simply be impractical and most entities will take equipment limitation exception that will not benefit the BES.* ***Unless stated in quantitative way (what and when) the requirement R2 provides no benefit to BES.***

M2: *The current version of M2 calls for dynamic simulations, studies, or other evidence* ***plus*** *having ACTUAL disturbance monitoring data proving the Requirement was met. The dynamic simulations/studies can be performed by third-party engineering contractors specializing in these activities to prove each site meets the first part. However, two questions must be addressed regarding actual data: (1) "How" actual data is acquired if SER, DDR and/or Fault Recording does not become mandated. NAGF made a similar point in their response.*
(2) "When" actual data must be submitted as evidence if we as GOs are not specifically asked for it by some other entity. Without some mandate for data, we as GOs are not going to know when every voltage disturbance that would have (should have) triggered a ride-through has occurred on the transmission system.

Attachment 1: *Are items 1 thru 10 requirements or they are notes supplementing Tables 1 and 2? Please define.*
More description needs to be provided on how to apply items 8, 9, and 10.

Attachment 2: *Are items 1 thru 5 requirements or they are notes supplementing Table 3? Please define.*
More description needs to be provided on how to apply item 5.

Likes 0	

Dislikes 0	

Response

Thank you for your comments.
R1: Please refer to the responses to NAGF and EEI
R2: Please refer to the measure M2 for additional specificity and examples for objectively evaluating compliance.
R2.1: Language is included to allow GOs the ability to respond to other planner/operator performance requirements as noted and avoid noncompliance with PRC-029.
R2.1.1/R2.1.2: The team advises to monitor the relevant quantities (for example: active current, active power, reactive current, reactive power, and the mode of operation). Additionally, a footnote was added to 2.1.1. Finally, refer to data requirements in PRC-028.
R2.1.3: There is no obligation or requirement for planners or operators to supply other performance requirements. The language related to having evidence of other performance requirements was considered necessary for a situation where an entity receives requirements from a planner or operator that would contradict PRC-029 requirements. The team included this as a means of allowing the GO to follow requirements as needed by planners/operators and not be in violation of PRC-029 requirements.
R2.3: The team has included this specific instance of allowing current block mode which would cause momentary cessation. This allowance is restricted to this instance to prevent tripping and is explained in more detail within the Technical Rationale.
R2.5: Language to allow different ramp rate requirements from planners/operators is already included. Also, for legacy equipment that cannot meet the requirements within PRC-029 due to hardware-based limitations, this would be covered in R4. Finally, R2.5 only refers to ramp rates after recovery from the mandatory operation region or permissive operation region to the continuous operation region.
Implementation Plan: Implementation Plan has been modified to include bifurcated implementation information between capability-based elements and performance-based elements. Essentially this is a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. This approach allows for entities to align their PRC-028 and the performance-based aspects of their PRC-029 implementation. Further, the disturbances identified by planners and operators within PRC-030, would trigger the request to hold data for demonstrating performance. Additional data requirements are established within PRC-030.
Attachments 1 and 2: The notes supplement information in regards to the tables and are not stand-alone requirements. The same interpretive method for the voltage and frequency -vs- time limits is applied within PRC-024.

Russell Ferrell - Luminant - Luminant Energy - 6

Answer	
Document Name	

Comment

. I support EEI's and Entergy's comments

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please refer to the responses to EEI and Entergy.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	
Document Name	
Comment	
For the applicability section, suggest adding "that owns equipment as identified in section 4.2" after "generator owner" similarly to the proposed PRC-030-1	
Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
Thank you for your comment. GOs would not be expected to comply for assets they do not own. Further, PRC-028, PRC-029, and PRC-030 have revised their applicability to use the new proposed IBR definition and the approved registration criteria changes to the NERC Rules of Procedure.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
“See comments submitted by the Edison Electric Institute”	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Please refer to the response to EEI.	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	
Document Name	
Comment	
none.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	
Document Name	
Comment	
See comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please refer to the response to EEI.	
Patricia Ireland - DTE Energy - 4, Group Name DTE Energy	
Answer	
Document Name	

Comment	
No comments at this time	
Likes 0	
Dislikes 0	
Response	
Thank you.	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	
Document Name	
Comment	
Ameren agrees with and supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please refer to the response to EEI.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
PRC-024-4: · We support creation of new standard PRC-029 to address IBR specific ride through issues, as both the different natures of synchronous and inverter-based generation and several recent events exhibiting significant IBR ride-through deficiencies and failures the causes of which are not relevant to synchronous generators. The approach to address IBR issues should be different to that of PRC-024 because there are too many other	

factors and causes of IBR ride-through failure not directly related to voltage and frequency protection settings that may and have caused ride-through deficiencies and failures.

· PRC-028 was voted out due to issues around definition of IBR criteria and implementation plan. Separate PRC-029 would allow PRC-024 to pass through the ballot process without many issues.

PRC-029-1:

· Support inclusion of Ride through requirement in the TERM section, which will get included into NERC Glossary of Terms.

· In all the requirements **IBR** is replaced with **Facility**, except the requirement R2.2 as **IBR**. In attachment 1 it is mentioned as **inverter-based resource facility.** That is not consistent.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
The terms for facility have all been modified to IBR to coincide with the new proposed definition of IBR from Project 2020-06.

Michael Dillard - Austin Energy - 5, Group Name Austin Energy

Answer	
Document Name	

Comment

Austin Energy supports comments posted by NAGF:

PRC-029:

General Comment: The NAGF believes that PRC-029 should allow for frequency ride through (“FRT”) exemptions similar to its treatment of voltage ride through (“VRT”) exemptions. The justification for allowing VRT exemptions in FERC Order 901 also apply to FRT. We believe the statement in FERC Order 901, paragraph 193 in response to ACP/SEIA’s comment in paragraph 188 does not preclude the standard drafting team from considering FRT exemptions due legacy equipment limitations. Here are a few reasons why:

1. If FERC's intent was to exclude Frequency Ride Through exemptions while allowing Voltage ride through exemptions, there would be more of a record established to support this differential treatment. *2. FERC responded to ACP/SEIA's comment on ride-through requirements as if they were only asking about voltage ride through requirements. FERC made no mention of frequency ride through requirements.* *3. Similar to FERC's rational for the consideration of voltage ride through exemptions, there are also older IBR technologies with hardware that would need to be physically replaced to meet frequency ride through requirements as well.* *4. NERC and the NERC Standard Drafting Teams have the technical expertise to address complex technical issues such as legacy equipment limitations that FERC does not have.* *Applicability Section, 4.2.2 – Recommend removing this section.* *Requirement R1: The NAGF notes that R1 only addresses voltage ride through and should be revised to include frequency ride through as well. In addition, R1 should address frequency ride through limitations for legacy IBR facilities.* *Measurement M1 – The proposed narrative reads more like requirements than measures; recommend to revise the narrative accordingly. In addition, the NAGF notes that the proposed narrative seems to assume that PRC-028 will be need to be approved/in place for PRC-029 to be a viable standard.* *Requirement 2.1.3: The narrative is unclear as to what is expected for this proposed requirement. Request that the narrative be rewritten/restructured to address this issue. In addition, it is unclear which entity will define the preference for active or reactive power. The NAGF suggests that the Transmission Planner (TP) should have the authority to define this preference. This recommendation also applies to Requirement 2, second bullet and Footnote 6.* *Requirement R2.5: The NAGF recommends that the narrative be revised to state that active power shall be restored when" the voltage at the high-side of the main power transformer returns to the Continuous Operating Region".* *Requirement R4: The draft narrative does not clearly specify who is responsible for approving the exemption. The NAGF requests the narrative be revised to address this issue.* *Measure M4: Recommend replacing the word "seeking: with "submitting" in the first sentence.*

Likes 0	
Dislikes 0	
Response	

Thank you for your comment.

Frequency/R3/Attachment 2 Exemptions: In Order No. 901, FERC directed NERC to determine whether the ride-through standard should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements, and only for voltage ride through performance for those existing IBRs that are unable to modify their settings without physical modification of equipment. See Order No. 901 at P 193. The drafting team determined that such an exemption was appropriate and it is included in Requirement R4. The drafting team does not have sufficient data at this time to determine whether additional frequency-based exemptions are appropriate and consistent with the overall reliability goals of Order No. 901. The drafting team does believe additional monitoring would be appropriate to determine how many entities would be affected by such an exemption and whether such an exemption would be consistent with overall Bulk-Power System reliability. To the extent such monitoring suggests that further exclusions would be appropriate, a future drafting team could make those changes in an expeditious manner. The affected entities could work with ERO Enterprise staff to address any compliance-related concerns in the interim. For this draft, however, the drafting team is pursuing a more conservative approach in line with the specific exemptions identified in Order No. 901.

Applicability Section – This section has been modified to reflect the current IBR definition as well as the approved changes to registration within the NERC Rules of Procedure. These modifications are consistent with changes to the applicability section within PRC-028 and PRC-030.

R1: R1 only covers voltage requirements and R3 is for the frequency requirements. The structure of PRC-029 and allowable exemptions will not work to combine these two.

Measures: the measures are written to provide specific examples of evidence needed for compliance. Further the implementation plan has been revised to bifurcate between capability-based elements and performance-based elements. Essentially this is now a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. This will allow entities to align their PRC-028 and the performance-based aspects for PRC-029 compliance.

R2.1.3: For Requirement R 2.1.3, revisions have been made clarify the requirement.

R2.5: Requirement R2.5 requires that active power return to the pre-disturbance level when voltage recovers to the continuous operating region, unless otherwise specified by the TP,PC, RC.

R4: Modifications to R4 have been made to clarify that the GO will submit the information to the CEA for "acceptance". Additionally, a footnote has been added to clarify this "acceptance".

M4. The modification was made to change "seeking" to "submitting".

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	

WECC suggests the DT should ensure that the labeling on the Project page of the Standard is accurate in terms of what is being considered. The "redline" version is not a true redline from PRC-024-3 it is a redline from a failed version of PRC-024-4 with the language that was voted down shown as "approved" (i.e., text appearing as not being changed.) This could be misleading. There is no mention of Attachment 2A or Attachment 2C in any of the Requirements. It is noted that there is a reference to Attachment 2B in the Quebec variance. Consider changing Requirement R2 language to reference Attachment 2A and incorporate current Attachment 2A language into Attachment 2. And incorporate Attachment 2C language into Attachment 2B. That provides clarity with a minimal change in Requirement R2 language. In theory, this is a set it and forget it Standard unless something changes. The data retention should reflect that condition and not be limited. GOs and TOs will have to be able to demonstrate settings when requested and can not simply say "the settings were done 6 years ago so no evidence is retained". There have been cases where a GO has indicated retrieval of settings required a third party because the GO did not have documentation. Absence of a failure (i.e., unit trip that would need to be reviewed to see if voltage/frequency was the root cause and if the associated relay responded within the "no-trip" zone) is not necessarily a successful reliability indicator and would require quite a bit of data to demonstrate reliable operation resulting in compliance.

Overall for PRC-024-4 WECC is supportive of the efforts and end results.

PRC-029-1

It is unclear why lower cased "facility" is used. In Footnote 2 "facility" is not used but "plant/resource" is used. In the Technical Rationale "plant/facility" is used. Please provide consistency in language within the Standard, the Requirements, and Technical Rationale.

Facilities Section 4.2 is extremely unclear in that it simply says "IBR Registration Criteria" for 4.2.2. Additionally, Footnote 2 does not consider any hybrid resource types (or Facility types or plant types).

R1 indicates "design and operation" which is a valid approach but "design" can be assessed reviewing settings (and simulations, etc.) but "operation" can only be assessed through a review of time periods where applicable voltage (or frequency) demonstrates a change that calls for operation per the Tables. The VSL for R1 is written in a manner that requires that level of assessment (e.g., entities would have to find a point in time where .89 Voltage existed and show they exceeded the minimum Ride-through time.) The VSL is written where a design issue is a lower VSL but the wrong setting would indicate that the operation could not adhere to Attachment 1. Measurement M1 mentions SER/FR/DDR which are covered in PRC-028-1 (Project 2021-04). Are those enough to demonstrate operation to Attachment 1 under the criteria set in the Tables? With PRC-028-1 setting data retention levels so short, the evidence suggested by Measurement M1 will require retention per Evidence Retention requirements in PRC-029-1 to be able to clearly demonstrate compliance.

If using capitalized "Transmission System" in the definition of "Ride-through" use it capitalized in Requirement 1 bullet 3. PRC-024 had MPT and GSU used and "defined". Consistency in use here in PRC-029 (with appropriate changes) to correlate with PRC-024 is appropriate but should be footnoted in Requirement R1 bullets 3 and 4 first prior to being called out in Requirement R2.1.

Measurement M1 is expansive and some of the details should be in the Technical Rationale rather than in a measure. As is, appears to be not consistent and should, at a minimum, include the word "shall" where needed as others Standards (including PRC-024) are written in this manner (e.g.",….shall have evidence…"). M1 does not mention bullet 2.

Requirement 2 will require a voltage excursion to demonstrate operation adhering to Attachment 1. What criteria constitutes a “voltage excursion”? Requirement 2.1- Consider adding a comma after “region” to be consistent with similar language in other parts of Requirement R2.

Requirement 2.1.1 The phrase “or available active power, whichever is less” appears to be supportive of the footnote regarding a frequency excursion but what if the “available active power” is lower than the pre-disturbance level of active power. “Less” could be zero output as the voltage at the MPT high-side could remain within the continuous operation range with the IBR disconnected.

Requirement 2.1.3 Please verify if that should be ”.95” per unit versus “95” per unit. Since this Requirement is within the Operations Horizon timeline, the reference to Transmission Planner and Planning Coordinator should be dropped. Furthermore, it is not clear what a GO would operate to if given conflicting orders by the RC and TOP. Consider limiting the “preference” to the TOP who is to set the system voltage expectations per VAR-001.

Requirement 2.2.- Consider “sub Part” formatting used in other Requirements versus bullets for consistency. Since this Requirement is within the Operations Horizon timeline, the reference to Transmission Planner and Planning Coordinator should be dropped. Furthermore, it is not clear what a GO would operate to if given conflicting orders by the RC and TOP. Consider limiting the “requirement” to the TOP who is to set the system voltage expectations per VAR-001. In this bullet the language says “each IBR” versus “each facility” as called out in other parts of Requirement R2. Is that correct?

Requirement R4 is a grandfathering clause and assumes each unit after the effective date will meet Requirements 1, 2, and 3. There should not be any additional implementation timeline built into a Requirement language as this Standard will take time to be approved and there is a proposed 6 month Implementation Plan. If there is a hardware limitation, it should be known Day 1 of the effective date of Standard and gathering of the limited information should have already been don ein the 6 months leading to the effective date. There is no requirement for an entity to replace the hardware limitation. The entire Requirement will result in documentation with no expectation of mitigation. What data does the DT have to support this exemption language? At a minimum, notification of an issue needs to be provided to the TOP and RC. Suggest a Corrective Action Plan with definitive time requirements to mitigate the issue (or explain why it can not be mitigated) be instituted here.

Footnote 9 may not be necessary as non-US Jurisdictional applicable government authorities have mechanisms in place to implement any Standard.

Within Requirement R4.1- 4.1.1- Call out specifics for consistency. Leaving as “other” invites inconsistency. Use “Ride-through” as that is a proposed defined term (versus “ride-through”) in 4.1.2. Be consistent in using “hardware” or “equipment” to avoid confusion throughout Requirement R4. Suggest removing the phrase “or that the limitation cannot be removed by software updates or setting changes” as this is limited to a hardware limitation exemption. Requirement R4.1.5 is ambiguous and clarity should be provided. Requirement 4.2 It is not clear why the Planning Coordinator and Transmission Planner is included here. Model data demonstrating the limitation should be provided through another mechanism. Including the Regional Entity here is not needed or recommended as Regional Entities are NOT subject to Standards. If the DT wants to include providing information to the Regional Entity place it in “Additional Compliance” section (similar to FAC-003) and recognize it as a data submittal. Recommend removal of Regional Entity from the Requirement language.

Measure M4 does not support Requirement R4 with regards to notification timeline in Requirement R4.3, sentence regarding submission of information in 4.1 should not be limited to the Regional Entity (alternatively that sentence could be removed as Regional Entity is covered in next sentence), and there is no information regarding the response timeline in 4.2.1. Furthermore, "experience from an actual event" indicates that the GO/TO could not adhere to the design and operation criteria set—equating to a possible noncompliance. If there is a hardware (or "equipment" depending on where consistency efforts lead) limitation that should be known in the design phase and addressed at that point

There is no corresponding frequency "hardware" limitation language if a facility can not adhere to Attachment 2.

Evidence Retention Section- Requirement R4 has no obligatory requirement to mitigate the hardware(equipment) limitation. As such, entities should be obligated to maintain information demonstrating compliance until the issues are mitigated. There should be language within the Requirement to correct the issue within a certain timeframe. As is, data demonstrating compliance for R4 would not be retained after 5 years and the entity would be held to performing per R1, R2, and R3 in subsequent compliance monitoring efforts unless tracking (and verification of compliance to R4) existed.

Attachment 1- Consider lowercasing "Through" in Table titles as it is part of the proposed defined single word "Ride-through". Consider lowercasing "Continuous Operating Region" as it is not a defined term nor is it capitalized in the Requirement language. Table 1 cannot have "1.1" and "1.10" be in the Mandatory Operation Region and Continuous Operation Region at the same time (e.g., the mathematical operator shows inclusion.) "1.1" should be shown a "1.10" for consistency. Footnote 10 is unclear as Type 3 and Type 4 wind turbines are IBRs and the use of "directly" in the footnote could leave some entities with Type 3 and Type 4 wind turbines to use Table 2. Simply say it is for Type 3 and Type 4 and leave the AC-Connected and directly connected verbiage out to avoid confusion. Note- Anytime a DT says it is clear the issue gets pushed into the compliance environment where suddenly no clarity exists. IBR is a definitive example of clear technical understanding but extremely unclear understanding when applying a compliance lens.

"Voltage Source Converter High Voltage Direct Current" is not defined nor explained. There are inconsistencies in how "Voltage Source Converter High Voltage Direct Current" is displayed—Footnote 1 is lower cased "v" and contains a hyphen after "High"; Bullet 3 does not have a hyphen in "VSC HVDC but bullet 2, Footnote 1, and Footnote 2 does.

Need to be consistent with the depiction of the Figures (in Attachment 2) in terms of what the boundary line depicts (inclusion or exclusion within the "Regions") as entities have struggled in the past versions of PRC-024 (and others). Figure 1 does not depict the 1.1 Voltage point and therefore appears to not support the Table (consider moving the 1.05 down to the boundary between the "1800 second" section and "no time requirement" section depiction while adding 1.1 to the upper boundary of the "1800 second" section.

Figure 2 does not reflect 1.05 Voltage point so the "1800 second" section appears to not be depicted appropriately. Consider adding the 1.05 Voltage point to the y-axis and redraw boundaries for "1800 second" section and "no time requirement" section. 1.05 should be the upper boundary of the "no time requirement" section. To provide consistency and clarity, Table 2 X-axis values should reflect the table values as Figure 1 reflected those (for Table 1) (i.e., show .32 and 1.2).

Since this is an Operating Horizon based Standard why would Bullet 5 depend upon the PC or TP? Bullet 5 and Bullet 6 do not use the same language (use of hyphens, use of neutral, use of ground). Is the intent of Bullet 10 to supersede Bullet 8 (i.e., does not matter is the time associated with the 4 deviations is below the time associated with the voltage?)

Attachment 2- Consider lowercasing “Through” in Table titles as it is part of the proposed defined single word “Ride-through”. Table 3 should reflect consistency in the System Frequency column. The frequency slot between 58.5 and 58.8 is not covered (suspect the 6th row needs adjustment as it is referencing the same frequency point—58.8). Additionally, it appears that there may be inconsistency in mathematical operators inclusion or exclusion of certain ranges. DT needs to confirm where 58.8 resides in terms of allowed time. Consider the Table below with bolded changes. For consistency with Voltage tables “N/A” versus “may trip” is suggested and for consistency the DT may consider a footnote as Tables 1 and 2 did in Attachment 1 regarding voltage.

System Frequency (Hz)

Minimum Ride-Through Time (sec)

≥64

N/A

< 64 and ≥61.8

6

< 61.8 and ≥ 61.5

299

< 61.5 and > 61.2

660

≤ 61.2 and **>** 58.8

Continuous

≤ 58.8 and **≥ 58.5**

660

< 58.5 and ≥ 57

299

< 57.0 and ≥ 56

6

< 56

N/A

PRC-024 had “MPT” and “GSU” used and “defined”. Consistency in use here in PRC-029 (with appropriate changes) to correlate with PRC-024 is appropriate.

VSLs- Requirement R1--DT should consider a different method to assign levels. While the Requirement language may say “each” perhaps a consideration for the VSL should be fleet-based. As written, the DT has created a “zero” tolerance Requirement. If the design is wrong the operation would be incorrect. Proving that should not take an event to demonstrate (as the compliance argument this will set up is that “there has not been a period where operation would have occurred”).

Requirement R2 and Requirement R3- Essentially same comments as VSLs for Requirement R1

Requirement R4- The notification timeframe appears to be initially set at 30 calendar days for all the VSLs (with adjustments considering the 30 calendar day foundation) but the Requirement R4 language indicates a foundation of “90 days” (also an issue noted in Measurement M4). With the timeframes associated

Implementation Plan—The last sentence regarding Requirement R4 needs to be struck or incorporated within the Requirement language. Requirement R4 says “hardware limitations” and does not specify the “coordinated protection and control settings”. To be clearer the DT should consider changing Requirement R4 language to “inability to modify coordinated protection and control functions”. There is a gap between the language regarding provision of a “copy to applicable entities” in the Lower VSL and what is in the Severe VSL. Effectively the Severe VSL covers 15 month plus 1 day to beyond 24 months. Is that the intent of the DT?

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

PRC-024-4
Project Page: The redline of PRC-024-4 is the redline of the standard since last posted. A redline of the standard since last approved (version 3) was not provided. Both redlines will be provided during the next ballot.
Attachment 2: The team identifies attachments 2A, 2B, 2C to be part of attachment 2. The team will continue to evaluate changes to demonstration of performance of ride-through within phase II of addressing the current SAR.

PRC-029-1
Plant/facility: The terminology has been changed to IBR to coincide with the new proposed definition for IBR. Additionally, this section has been modified to include the registration criteria within the recently approved changes to the NERC Rules of Procedures. The team was advised to hold on usage of specific language until the changes had been approved.
Applicability for Sub-BES IBR: This section has been modified to include the registration criteria within the recently approved changes to the NERC Rules of Procedures. The team was advised to hold on usage of specific language until the changes had been approved.
Measures: The SER/FR/DDR data are necessary to demonstrate compliance with the operational performance aspects of PRC-029. Additional review of design documents, simulations, etc. is necessary to demonstrate compliance with the design capability-based aspects of PRC-029.
Ride-through definition: The definition for Ride-through has been revised.
Measures. The team has reinserted the word “shall” into the measures; this is shown as “shall have”. The team also agrees that usage of “retain” is preferable language and have made this change to all measures.
Data retention and identifying excursions: disturbances identified by planners and operators within PRC-030 would trigger the request to hold data for demonstrating performance. Additional data requirements are established within PRC-030.
R2.1.1: Additionally, a footnote was added to 2.1.1 to clarify returning to available power.
R2.1.3: 95 pu has been corrected to 0.95 pu. There is no obligation or requirement for planners or operators to supply other performance requirements. The language related to having evidence of other performance requirements was considered necessary for a situation where an entity receives requirements from a planner or operator that would contradict PRC-029 requirements. The team included this as a means of allowing the GO to follow requirements as needed by planners/operators and not be in violation of PRC-029 requirements.
R2.1: Language is included to allow GOs the ability to respond to other planner/operator performance requirements as noted and avoid noncompliance with PRC-029.
R2.2: Bullets are used when there is more than one option (OR) and are appropriate for this instance. Numbers are used when each subpart must be performed (AND). “facility” has been removed.
Implementation Plan: Implementation Plan has been modified to include bifurcated implementation information between capability-based elements and performance-based elements. Essentially this is a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. This approach allows for entities to align their PRC-028 and the performance-based aspects of their PRC-029 implementation. Further, the disturbances identified by planners and operators within PRC-030, would trigger the request to hold data for demonstrating performance. Additional data requirements are established within PRC-030.
R4: The 4.1.1 has the word “other” removed. The uppercase “Ride-through” term was corrected. Usage of “hardware” -vs- “equipment” has been corrected throughout. The team sees the language regarding software limitations or settings to be clarifying language. R4.1.5 appears to be clear to

the team. If additional information is needed, that would be requested through R4.2. R4 does not require model data to be provided. The Regional Entity has been changed to the CEA. The team has been advised that inclusion of CEA here is appropriate and has precedent. **M4**: The measure has been adjusted to include R4.2.1 response times and R4.3 response times from the entity. Requirements cannot be directed to Regional Entities in Standards. Concerns regarding acceptability of information that identifies a hardware based limitation will be resolved through the CEA acceptance. The VSL/VRF tables have been updated accordingly. **Frequency/R3/Attachment 2 Exemptions**: In Order No. 901, FERC directed NERC to determine whether the ride-through standard should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements, and only for voltage ride through performance for those existing IBRs that are unable to modify their settings without physical modification of equipment. See Order No. 901 at P 193. The drafting team determined that such an exemption was appropriate and it is included in Requirement R4. The drafting team does not have sufficient data at this time to determine whether additional frequency-based exemptions are appropriate and consistent with the overall reliability goals of Order No. 901. The drafting team does believe additional monitoring would be appropriate to determine how many entities would be affected by such an exemption and whether such an exemption would be consistent with overall Bulk-Power System reliability. To the extent such monitoring suggests that further exclusions would be appropriate, a future drafting team could make those changes in an expeditious manner. The affected entities could work with ERO Enterprise staff to address any compliance-related concerns in the interim. For this draft, however, the drafting team is pursuing a more conservative approach in line with the specific exemptions identified in Order No. 901. **CAPs**: Exemptions from R4 are limited to those with hardware-based limitations only. Corrective action plans – or other terms to mitigate the limitation may be identified as part of PRC-030 analysis, or other planning/operational studies that evaluate the system. **M1**: R1 bullet 2 refers to equipment limitations according to R4. The measure for R4 is detailed in M4. **Attachment 1 bullet 4 (previously #5)**: TO has been added. **Attachment 1 bullets 4 and 5 (previously 5 and 6)**: have been adjusted to use the same usage of hyphens. **Attachment 1 Bullets 7 and 9 (previously 8 and 10)**: Yes, this is correct. **Attachment 2 table #3**: The table values and operands have been corrected. **Plant/facility**: The terminology has been changed to IBR to coincide with the new proposed definition for IBR. Additionally, this section has been modified to include the registration criteria within the recently approved changes to the NERC Rules of Procedures. The team was advised to hold on usage of specific language until the changes had been approved. **Main power transformer**: The footnote for the main power transformer has been moved to the first occurrence of its usage in PRC-029. The standard does not use GSU. **VSL for percentage of fleet**: The severity level is based on the occurrence of the noncompliance. Also, the impact to the system is dependent on a number of other influencing factors (i.e., loading, local system strength, etc.). Extent of condition analysis is conducted in later stages of the CMEP. **Measure 4 and VSL table**: These have been corrected to the correct response times.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	

Response from ITC Holdings: “IBR Registration Criteria” is not an applicable Facility. The applicabilities of PRC-028, PRC-029, and PRC-030 need to be aligned. E.g. A TO that owns the VSC-HVDC connection for offshore wind is subject to PRC-029 but not PRC-028 or PRC-030. R1 has no value as a standalone requirement and should be incorporated into R2. In other words, you can’t violate R1 without also violating R2, so eliminate R1 or incorporate its subtle value into R2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment **sub-BES IBR**: The applicability section has been modified to include the registration criteria within the recently approved changes to the NERC Rules of Procedures. The team was advised to hold on usage of specific language until the changes had been approved. **Alignment:** This issue has been addressed. **R1/R2**: R1 requires ride-through within the must Ride-through zone. R2 includes additional performance requirements beyond tripping/momentary cessation/failing to Ride-through.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
Minnesota Power supports EEI’s comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response to EEI.	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE has the following comments on the PRC-024-4 draft:

- Requirements R1, R2, and R4 use the term 'Facility' when referencing synchronous generator, type 1 or type 2 wind resource, or synchronous condenser. Requirement R3, however, uses a description of the Facility. Texas RE recommends using the term Facility to be consistent with the other requirements. Texas RE recommends the following revision (in bold):

R3. Each Generator Owner and Transmission Owner shall document each known regulatory or equipment limitation that prevents **an** its **synchronous generator, type 1 or type 2 wind resource, or synchronous condenser Facility**, with applicable frequency or voltage protection from meeting the protection setting criteria in Requirements R1 or R2, including (but not limited to) study results, **technical incapability identified after** experience from an actual event, or manufacturer's advice.

'Technical incapability identified after' language is added to clarify that the Facility Owner must conduct detailed analysis to ensure that the Facility is technically incapable of providing the required system support and the specific technical limitations should be documented.

- Please update footnote 4 (Requirement 2.1) on page 5 of 22 (clean version) - changes in bold font:

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 synchronous generator(s), type 1 or type 2 wind resource(s), or synchronous condenser(s); or (ii) provide signals **to same** to trip **the same Facilities**.

- In Requirement R4, Texas RE recommends that each Generator Owner and Transmission Owner shall provide its applicable protection settings to Planning Coordinator *and* Transmission Planner. The applicable data should be provided to both the Planning Coordinator and Transmission Planner so the study model(s) used by Planning Coordinator and Transmission Planner can be updated concurrently. Texas RE recommends the following revision (in bold):

R4. Each Generator Owner and Transmission Owner shall provide its applicable protection settings associated with Requirements R1 and R2 to the Planning Coordinator **or and** Transmission Planner that models the associated Facility 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 settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of protection setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

It is important that the applicable data is provided to the Planning Coordinator and Transmission Planner so that the study model(s) used by PC and TP can be updated concurrently.

- Technical Rationale document - Texas RE recommends the Facilities section include the Frequency and Voltage Protection Settings for Type 1 and Type 2 Wind Resources in addition to the Synchronous Generators and Synchronous Condensers in the title document since they were added to section A 4.2.1.4 of the standard. Texas RE recommends the following revision (in bold):

Facilities (4.2)

Applicability Facilities subparts in Section 4.1**2**.1 were modified to restrict PRC-024-4 to synchronous generators **and Type 1 and Type 2 Wind Resources**. Section 4.2.2 was added as new subparts to identify which synchronous condensers and equipment.

PRC-029-1 Comments

- Ride-through definition: Ride-through capability is the ability of the resource to continuously deliver power during a disturbance event. It appears the phrase 'continuing to operate' used in the Ride-through definition is intended to state that the Facility needs to deliver power in response to system conditions. Texas RE recommends the following revision (in bold):

Ride-through: Remaining connected, synchronized with the Transmission System, and continuing to operate **by delivering power** in response to System conditions through the time-frame of a System Disturbance.

Applicability Section 4.2.1: Footnote 2 refers to 'offshore wind plants connecting via dedicated VSC-HVDC". Texas RE recommends revising this footnote to include offshore and on-land VSC-HVDC. Texas RE recommends the following revision (in bold):

For the purpose of this standard, "inverter-based resources" refers to a collection of individual solar photovoltaic (PV), Type 3 and Type 4 wind turbines, battery energy storage system (BESS), or fuel cells that operate as a single plant/resource. In case of **offshore any** wind plants connecting via a dedicated VSC-HVDC, the inverter-based resource includes the VSC-HVDC system.

- Applicability Section 4.2.2: Texas RE recommends revising the verbiage to "**Resource which meets** IBR Registration Criteria".

- Requirement R1: Texas RE recommends clarifying the first bullet to state that the facility is electrically disconnected in order to clear a fault within its protection zone as designed. Texas RE recommends the following revision (in bold):

The facility needed to electrically disconnect in order to clear a fault **within its zone of protection as designed**;

- Measures: Texas RE noticed the Measures for IBRs in PRC-029-1 are more burdensome than the Measures for synchronous generators in PRC-024-4. Though Measures are not enforceable, they are instructive in which activities could be used to demonstrate compliance with a Requirement. For synchronous generators in PRC-024-4, the Measures indicate that a Generator Owner or Transmission Owner can demonstrate compliance by providing a settings sheet or supporting calculations, or the synchronous generator can instead rely on dynamic simulation studies. In contrast, the Measures in PRC-029-1 indicate that the IBR shall have dynamic simulations, studies, or other evidence to demonstrate the design of each Facility, and the Measures also indicate that the IBR shall have evidence of actual disturbance monitoring to demonstrate performance of the Facility in actual historical Ride-through events. These Measures appear to be more burdensome for IBRs than for synchronous generators and also appear to suggest obligations exist beyond what is stated in the enforceable Requirement text.

- Measures: Since the measures are not enforceable, Texas RE encourages the SDT to consider removing shall statements from the measures. Texas RE recommends using similar verbiage to the measures in the CIP standards, which say “Examples of evidence may include, but are not limited to…”

- Measure M1: The first sentence in Measure M1 shows the word “shall” removed, but nothing was put in its place. Is that the intent of the SDT?

- Requirement Part R2.1.3: Texas RE recommends revising Requirement Part 2.1.3 from passive to active voice so it is clear that the Generator Owner or Transmission Owner is the entity giving preference. Texas RE recommends the following revision (in bold):

If the facility cannot deliver both active and reactive power due to a current or apparent power limit or reactive power limit, when the applicable voltage is below 95% per unit and still within the continuous operation region, **then the Generator Owner or Transmission Owner shall give preference to active or reactive power as** required by the Transmission Planner, Planning Coordinator Reliability Coordinator, or Transmission Operator.

- Requirement Part 2.5: If a small number of the inverters or turbines trip offline at a facility during a fault while the voltage remains in the mandatory operation region, will that facility be in violation of Requirement R 2.5?

- Requirement R4: Texas RE noticed Requirement R4 does not provide an opportunity for legacy Facilities to identify an equipment limitation after 12 months from the effective date of PRC-029-1. PRC-029-1 R1 provides an exception for IBRs that document equipment limitations in accordance with R4. In PRC-029-1 R4, a Facility that existed before the effective date of PRC-029-1 shall identify and document information supporting identified hardware limitations no later than 12 months from the effective date of PRC-029-1. Is the intention that equipment limitations identified after this 12-month window will not be eligible for the exception in PRC-029-1 R1? For a Facility that identifies an equipment limitation in the 13th month or beyond, does the SDT intend for that IBR to still be able to document the equipment limitation and qualify for the exception in R1, albeit with the obligation to submit a Self-Report for failing to meet the 12-month deadline in R4? Alternatively, does the SDT intend that an IBR that does not identify an equipment limitation within the 12-month window should never be able to qualify for the exception in R1?

- Requirement R4: Texas RE recommends the measures include evidence that the Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and to the Regional Entity the documented information supporting the identified hardware limitation.

- Attachment 1: Figure 1: Voltage Ride-Through Requirements for AC-Connected Wind Facilities graphical representation should be corrected to match Tables 1 and 2. The continuous operating region is between 1.05-0.9 and Continuous Operating Region (1800 seconds) time delay is greater than 1.05-1.1 voltage level. In Figure 1, Texas RE recommends adding 1.1 above 1.05 in the Continuous Operating Region (1800 seconds). In Figure 2, Texas RE recommends replacing 1 with 1.05.

- Attachment 2: Frequency Ride – Through Criteria table 3 should be updated to reflect the correct low frequency levels for 660 seconds time delay.

≤ 58.8 and < 58.8 58.5

- Page 16 onward: The Mandatory Operation Region and Continuous Operation Region phrases should be lowercase to match changes made to rest of the standard.

Texas RE noticed the word “facility” is lowercase throughout (redline shows it replaces IBR, e.g. in R1). If the intent is to be consistent the applicability, Texas RE recommends using the term “applicable facility” to refer back to 4.2 Applicability section.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
PRC-024
Facility: The team agrees and has modified R3 to use “Facility”, consistent with R1 and R2.
Equipment limitations: R3 already requires equipment limitations be documented and that information regarding the limitation much by communicated.
Footnote 4: This footnote has been corrected as suggested.
R4: The team identifies that the information is available upon written request.
TR PRC-024: The technical rationale will be revised to include type 1, type 2 wind.

PRC-029
R1 – bullet 1: The team identifies that existing language is sufficient.
Measures: Measures M1-M3 have been revised to address using examples to achieve objectives.
R2.1.3: Active voice language has been included.
R2.5: If partial tripping prevents the IBR from returning to pre-disturbance active/available power level, it would result in potential noncompliance. Footnote #10 has been added for clarity.
R4: The purpose of this requirement is to identify the extent of legacy Facilities requiring an exemption (and the associated reliability impacts) as soon as is reasonably feasible. <u>Entities should exercise all due diligence to identify their equipment limitations within this 12-month period</u>. However, to the extent an entity determines that they have an equipment limitation after this 12 month period, they may still apply for the exemption, subject to any compliance implications for failing to apply within the 12-month period.
Attachment 2: This table has been corrected.
Terminology: The operation region names have been addressed. Usage of “facility” has been replaced with the proposed term “IBR”.

John Pearson - ISO New England, Inc. - 2

Answer	

Document Name	
Comment	
ISO New England signs onto comments of the Standard Review Committee of the ISO/RTO Council.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see the response to the ISO/RTO Council.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	
Document Name	
Comment	
• Bureau of Reclamation (BOR) notes that PRC-024-4 draft 2 is redlined to the draft 1 (clean version). Draft 2 has accepted all of the redlines from Draft 1, yet the ballot for Draft 1 was below the two-thirds majority of the weighted Segment votes requirement for approval per Appendix 3A of NERC's standard process manual V5 dated 11-28-2023. • Recommend SDT provide a separate comment form for each Standard under development. • PRC-029-1 is not applicable to BOR. • BOR recommends an 18-month implementation timeline for both standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Project Page**: The redline of PRC-024-4 is the redline of the standard since last posted. A redline of the standard since last approved (version 3) was not provided. **Comment forms**: The team will take this under advisement for the next ballot. **Implementation Plan**: The Implementation Plan has been modified to include bifurcated implementation information between capability-based elements and performance-based elements. Essentially this is a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. This approach allows for entities to align their PRC-028 and the performance-based aspects of their PRC-029 implementation.	

Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	
Comment	
• AES CE fully supports the SEIA working group and other industry comments on allowing exceptions for frequency ride through. • AES CE is concerned by the updated language in several Measures reading "Each Generator Owner and Transmission Owner have evidence of actual disturbance monitoring…" and believe that the simulations and studies used to demonstrate compliant design should be sufficient, similar to PRC-024. There will be many plants that do not experience an applicable disturbance before this Standard becomes effective and therefore cannot demonstrate adherence to ride-through requirements as prescribed. We are also concerned about expectations for this Measure as time goes on, are we expected to document and record every applicable disturbance and the asset's performance? Additional clarification is required if the Drafting Team believes that actual disturbance monitoring language should remain in the Measures. • The required protection is not currently modeled in basic models and will require substantial effort to ensure we can perform as required. AES CE requests that the Implementation Plan be modified to use a phased-in approach for existing sites to allow adequate time to prepare for these performance requirements. We suggest that the Implementation Plan for PRC-029 should align or lag the Implementation Plan for PRC-028.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. **Frequency/R3/Attachment 2 Exemptions**: In Order No. 901, FERC directed NERC to determine whether the ride-through standard should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements, and only for voltage ride through performance for those existing IBRs that are unable to modify their settings without physical modification of equipment. See Order No. 901 at P 193. The drafting team determined that such an exemption was appropriate and it is included in Requirement R4. The drafting team does not have sufficient data at this time to determine whether additional frequency-based exemptions are appropriate and consistent with the overall reliability goals of Order No. 901. The drafting team does believe additional monitoring would be appropriate to determine how many entities would be affected by such an exemption and whether such an exemption would be consistent with overall Bulk-Power System reliability. To the extent such monitoring suggests that further exclusions would be appropriate, a future drafting team could make those changes in an expeditious manner. The affected entities could work with ERO Enterprise staff to address any compliance-related concerns in the interim. For this draft, however, the drafting team is pursuing a more conservative approach in line with the specific exemptions identified in Order No. 901. **Measures**: the measures are written to provide specific examples of evidence needed for compliance. Further the implementation plan has been revised to bifurcate between capability-based elements and performance-based elements. Essentially this is now a phased-in implementation plan	

whereas each entity will be required to respond to the full requirement over time. This will allow entities to align their PRC-028 and the performance-based aspects for PRC-029 compliance.	
Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	
Document Name	
Comment	
PNM agrees with the comments made by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please refer to the response to EEI.	
Carver Powers - Utility Services, Inc. - 4	
Answer	
Document Name	
Comment	
The term “active power” is not defined and appears to be used in conjunction with Real Power. Recommend consistency throughout the standards when using Real Power vs active power, such as MOD-025, BAL-001, and many others. Recommend the DT reevaluate the implementation period of 6 months. Recommend making implementation period 18 months or greater to account for the need for working with OEMs to implement any setting changes and the need for IBR settings reviews conducted by third parties, as necessary.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. **Active Power**: The terms have been replaced with those from the glossary.	

Implementation Plan: The Implementation Plan has been modified to include bifurcated implementation information between capability-based elements and performance-based elements. Essentially this is a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. This approach allows for entities to align their PRC-028 and the performance-based aspects of their PRC-029 implementation.	
Daniel Gacek - Exelon - 1	
Answer	
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see the response to EEI.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see the response to the NPCC Regional Standards Committee	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	

Document Name	
Comment	

EEI offers the following Comment to Draft 2 for PRC-024 and PRC-029.

PRC-024-4 Comments:

EEI has no substantive concerns with any of the proposed changes to PRC-024-4 but point out a minor typo in Requirement R2 (below).

R2. Each Generator Owner and Transmission Owner shall set applicable voltage protection in accordance with PRC-024-4 Attachment 2, such that the applicable protection does not cause the Facility to which it is applied **to** trip within the "no trip zone" during a voltage excursion at the high-side of the GSU or MPT, subject to the following exceptions: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

PRC-029-1 Comments:

While EEI appreciates that changes made to address our previous comments for the 1st draft of PRC-029-1, we have some new concerns that need to be addressed.

Our high level concerns are described in our comments below:

1. The Standard attempts to redefine the approved definition of IBR by adding VSC-HVDC systems after the IBR definition was approved by the industry.
2. The Standard adds TOs to this Standard solely to address VSC-HVDC systems, yet no technical justification has been provided. Moreover, these systems were not identified in FERC Order No. 901, or this SAR and they were not clearly identified in the Applicability Section of this proposed Reliability Standard.
3. EEI is concerned with the inclusion of requirements that are not clearly defined or set by multiple registered entities (i.e., TP, PC, RC, or TOP). This creates regulatory confusion and places IBR-GOs in a position where they may need to comply with any number of entities without clearly defining who is responsible. (See Requirement R2, subpart 2.1.3; subpart 2.2 (bullet 2); subpart 2.5) Moreover, the identification of multiple entities who could be responsible creates a situation where IBR-GOs will have reporting obligations to multiple entities because no single entity is identified as being responsible. (See requirement R4, subparts 4.2 & 4.2.1; subpart 4.3) We further note that none of the entities identified (i.e., TP, PC, RC, or TOP) are identified within the Applicability section of this proposed Reliability Standard. All of this can create confusion and places a considerable burden on the IBR-GOs that needs to be resolved and clarified.
4. Throughout this Reliability Standard there is use of non-glossary terms (i.e., active power vs. Real Power) where glossary terms are available and should be used. While in other cases glossary terms are used but not capitalized. (e.g., reactive power vs. Reactive Power) Greater efforts should be made to use NERC Glossary terms where appropriate and capitalize those terms, as required.

Detailed Concerns

Ride-through Definition Comments:

EEI does not support the proposed definition for "Ride-through" as proposed because it is too vague and contains no defined limits, as proposed. We recommend the following changes:

Ride-through: Ability to withstand voltage or frequency Disturbances within defined regulatory limits remaining connected, synchronized with the Transmission System, and continuing to operate**.**

Applicability Section Comments:

Footnote 1: EEI does not support adding TO that own VSC-HVDC systems because this was not a scope item and is therefore not be included in the scope of this SAR. Moreover, Footnote 1 conflicts with Footnote 2 which defines VSC-HVDC as an IBR, which is again does not in alignment with the approved definition of an IBR.

Footnote 2: EEI does not support Footnote 2 because it expands the definition of IBRs beyond what was recently approved by the industry, noting the expansion of IBRs to include VSC-HVDC. Furthermore, there was no technical justification for adding VSC-HVDC and the SAR did not include adding VSC-HVDC systems to this project. For this reason, we ask that the definition of IBR not be expanded through footnotes and suggest that the DT submit a technical justification for adding VSC-HVDC systems to the applicability section of this Standard, rather than redefining an approved definition in a footnote.

To address our concerns related to Footnotes 1 & 2 we suggest that if VSC-HVDC systems are to be classified as IBRs, then the approved definition should be pulled by NERC and resubmitted with those resources added to the definition and resubmitted to the industry for approval. Alternatively, VSC-HVDC systems could be defined separately, and that definition submitted to the industry for approval. In both cases, a technical justification should be provided to the industry that defines the issues and risks to BPS reliability that VSC-HVDC systems pose.

EEI suggests that if the DT believes that certain IBR capabilities as identified under Requirement R2 need (or may need) to be specified then they should identify the entity who should be responsible among the four identified (i.e., TP, PC, RC or TOP); add them to the applicability section of this Reliability Standard; add clear requirements and adjust the reporting obligations for the IBR-GO under Requirement R4.

Requirement R1 & R2 Comments: EEI does not agree with the inclusion of Transmission Owners because they would only have an obligation under this Reliability Standard if VSC-HVDC systems were included. Given we do not support the inclusion of VSC-HVDC systems without a technical justification and modified SAR, we ask that Transmission Owners be removed from Requirement R1.

Additional Requirement R2 Comment: EEI suggests that there should be clearer linkage between Requirement R1 and R2. We are also concerned that R2 only exempts documented equipment limitations but does not also include the exemptions provided within R1. To address these concerns, we offer the following edits to Requirement R2: R2. Each Generator Owner shall ensure the design and operation **of** the voltage performance **of its IBR Facilities** adheres to the following **conditions** in accordance with Requirement **R1**. [Violation Risk Factor: High] [Time Horizon: Operations Assessment] EEI also suggests that the “each facility” be replaced with “IBR Facilities” because the use of the uncapitalized version of facility is too broad, making compliance requirement unclear. **Measures M1 & M2:** EEI is concerned that M1 & M2 contains measures that are overly prescriptive providing little discretion to IBR-GOs in demonstrating their compliance with Requirements R1 and R2 that seem to align more with a Requirement than a Measure. To address our concerns, we offer the following suggested changes to M1 and suggest similar changes be made to M2: **M1.** Each Generator Owner **shall** have evidence **that supports the** Ride-through **capability of each of their facilities**, as specified in Requirement R1. (e.g., simulations, studies, recorded data from disturbance monitoring equipment, etc.) If the Generator Owner choose to utilize Ride-through exemptions that occur within the “must Ride-through zone” and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner **shall** also have evidence **supporting that exemption. (e.g., studies, simulations or supporting data from disturbance monitoring equipment)** **Requirement R3 & R4:** EEI does not support the inclusion of Transmission Owners within Requirements R3 & R4 for the same reasons identified above.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. **PRC-024** **R2**: The errata has been corrected. **PRC-029** **IBR Definitions**: While the definition for IBR was approved, it included the term IBR Unit, which was not approved and did not have an acceptable resolution to industry and the team. As such the language was considered to be unenforceable. The teams were advised to remove usage of unapproved terms until a clear path forward with the definitions could be assured. Project 2020-06 is moving forward with another version of a definition of IBR that removes the embedded usage of another term. The next drafts of Milestone 2 related projects, including PRC-029, will include

this new term as proposed by 2020-06. Additional definitions for parts within an IBR plant/facility will be developed by projects associated with Milestone 3 as determined by those teams. Further**,** regarding sub-BES IBR: the applicability section has been modified to include the registration criteria within the recently approved changes to the NERC Rules of Procedures. The team was advised to hold on usage of specific language until the changes had been approved. **Transmission Owner**: The transmission owner has been removed from PRC-029. **Other Performance Requirements:** The language related to having evidence of other performance requirements was considered necessary for a situation where an entity receives requirements from a planner or operator that would contradict PRC-029 requirements. The team included this as a means of allowing the GO to follow requirements if needed by planners/operators and not be in violation of PRC-029 requirements. Planners and operators are not required to provide other performance requirements and are not applicable to this Standard. The language reads that as long as an entity is able to demonstrate that deviations from PRC-029 performance are due to other requirements provided by any of the listed entities, that the GO would not be in noncompliance. **Applicability:** As a follow up to the response for **Transmission Owner** and **Other Performance Requirements**, the team identifies no obligation or requirement for entities, other than the GO, for any requirements in PRC-029. **Active Power**: The terms have been replaced with those from the glossary. **Ride-through definition**: The definition for Ride-through has been revised. **R1/R2**: R1 requires ride-through within the must Ride-through zone. R2 includes additional performance requirements beyond tripping/momentary cessation/failing to Ride-through. **Measures:** the measures are written to provide specific examples of evidence needed for compliance. Further the implementation plan has been revised to bifurcate between capability-based elements and performance-based elements. Essentially this is now a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. This will allow entities to align their PRC-028 and the performance-based aspects for PRC-029 compliance.

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	
Document Name	
Comment	
Regarding PRC-024-4, SMUD has no comments and supports the Standard Drafting Team (SDT) in this latest version of the Standard. Regarding PRC-029-1, SMUD has the following comments:	

1) The voters in Project 2020-06, Inverter-based Resource Glossary Terms draft #2, approved the definition of IBR on April 8, 2024, which is different than the definition proposed in Footnote 2 of PRC-029-1. Using the term "inverter-based resources" and defining it with Footnote 2 is inefficient and would create two definitions for the same resource. The SDT of PRC-029-1 should coordinate with the SDT of Project 2020-06, and NERC staff, to ensure the definition of IBR and new PRC-029-1 are submitted to FERC simultaneously thereby eliminating another ballot for PRC-029-1 to add the NERC Glossary Term for IBR into the standard and eliminate confusion between IBR and "inverter based resources." 2) Requirement R2.2, the term "IBR" should be replaced with "facility" to be consistent with the rest of the Standard. As currently written, Requirement R2.2 states "While voltage at the high-side of the main power transformer is within the mandatory operation region as specified in Attachment 1, each ***IBR*** [emphasis added] shall…" 3) Requirement R2.1.3 should specify only one entity. As currently written, this sub-requirement gives Transmission Planners, Planning Coordinators, Reliability Coordinators, or Transmission Operators the ability to require the facility to deliver active or reactive power. The SDT should make it clear which single entity can set the requirement to avoid any conflicts. 4) Measure 1 and Measure 2 contain the language "Each Generator Owner and Transmission Owner also have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data ***to demonstrating that the operation of each facility did adhere to performance requirements*** [emphasis added]…" Some facilities may not have sufficient data from actual system disturbances by the time this Standard becomes mandatory and enforceable. The SDT should allow for the use of simulations and studies to demonstrate compliant design, similar to PRC-024, in such cases where the facility does not have evidence of an actual disturbance.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. **IBR Definitions**: While the definition for IBR was approved, it included the term IBR Unit, which was not approved and did not have an acceptable resolution to industry and the team. As such the language was considered to be unenforceable. The teams were advised to remove usage of unapproved terms until a clear path forward with the definitions could be assured. Project 2020-06 is moving forward with another version of a definition of IBR that removes the embedded usage of another term. The next drafts of Milestone 2 related projects, including PRC-029, will include this new term as proposed by 2020-06. Additional definitions for parts within an IBR plant/facility will be developed by projects associated with Milestone 3 as determined by those teams. Further**,** regarding sub-BES IBR: the applicability section has been modified to include the registration

criteria within the recently approved changes to the NERC Rules of Procedures. The team was advised to hold on usage of specific language until the changes had been approved.
Plant/facility: The terminology has been changed to IBR to coincide with the new proposed definition for IBR. Additionally, this section has been modified to include the registration criteria within the recently approved changes to the NERC Rules of Procedures. The team was advised to hold on usage of specific language until the changes had been approved.
R2.1.3: There is no obligation or requirement for planners or operators to supply other performance requirements. The language related to having evidence of other performance requirements was considered necessary for a situation where an entity receives requirements from a planner or operator that would contradict PRC-029 requirements. The team included this as a means of allowing the GO to follow requirements as needed by any planner/operator and not be in violation of PRC-029 requirements.
Implementation Plan: The Implementation Plan has been modified to include bifurcated implementation information between capability-based elements and performance-based elements. Essentially this is a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. This approach allows for entities to align their PRC-028 and the performance-based aspects of their PRC-029 implementation.

Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

Elevate appreciates the opportunity to comment on the draft NERC standards, particularly those pertaining to future IBR NERC Reliability Standards and FERC Order No. 901 directives.

Adoption of, or Alignment with, IEEE 2800-2022

Elevate continues to strongly encourage NERC to reconsider adoption of IEEE 2800-2022. The unwillingness to adopt IEEE 2800-2022 by NERC is leading to entirely duplicative efforts that are not serving any additional value as compared to the work conducted in the IEEE 2800-2022 developments. It does not appear that a holistic approach and strategy is being taken to meet the FERC Order No. 901 directives, which is leading to very low ballot scores, significant rework, and misalignment with industry recommended practices.

The draft NERC PRC-029 is duplicative with IEEE 2800-2022 Clause 7 yet only covers a small fraction of the IBR-specific capability and performance requirements outlined in that clause. Therefore, there is no clear reliability benefit versus the cost of implementation PRC-029 as compared with IEEE 2800-2022 and the recommendations set forth in the NERC disturbance reports and guidelines.

Elevate strongly recommends a single NERC standard that adopts IEEE 2800-2022 in a uniform and consistent manner. NERC can also issue a reliability guideline or implementation guidance that supports industry implementation of the standard. Rather than recreate parts of IEEE 2800-2022 inconsistently over multiple different standards, Elevate recommends a singular standard for BPS-connected IBR capability and performance requirements related to IEEE 2800-2022. Additional NERC standards can be developed where needed in situations where they are not covered directly with IEEE 2800-2022 (e.g., NERC PRC-030).

Concerns with Draft PRC-029

If the draft PRC-029 standard is to be pursued as currently structured, Elevate would like to highlight the following concerns:

Inconsistencies with PRC-029 and IEEE 2800-2022: There are numerous inconsistencies in the draft standard language and attachment 1 and 2 when compared to IEEE 2800-2022. These should be considered and reviewed for clarity and completeness in the standard. The option to cite IEEE 2800-2022 and use the requirements in the IEEE 2800-2022 directly should be allowed over just the use of Attachment 1/2 (i.e. give each GO/TO the ability to use either of these guides to base their performance off on).

IEEE 2800 identifies the following items, but the standard does not support. Clarification/review should occur for each of these items:

IEEE 2800 recognizes FRT requirement limitations, but the standard does not.

IEEE 2800 recognizes exceptions for Negative-sequence voltage exceeding thresholds

IEEE 2800 recognizes Volts/Hz limitations, but the standard does not.

IEEE 2800 recognizes 500kV system voltages are actually operated in the range of 525kV and therefore has equipment rated to 550kV. These 500kV operating conditions should be considered in the standard.

In IEEE 2800 the frequency ride-through criteria defines 10-minute time periods whereas the standard defines them in a 15 minute time period (Table 3 of Attachment 2). This should be clarified and identified.

Attachment 1: Voltage Ride-through criteria has issues that should be corrected. Row 2, voltage (per unit) has an error, the mathematical operand should be "greater than" for the 1.10 value; this entry should read "=< 1.20 and > 1.10".

Attachment 1: frequency ride-through criteria should be updated to fully match with IEEE 2800. Creating a different FRT ride-through curve without adequate technical justification will continue to challenge the industry.

The SDT should consider allowing for FRT and V/Hz exemptions, similar to what is already in place for VRT exemptions. Legacy equipment limitations apply to FRT, V/Hz, and VRT ride-through requirements, so exemptions should be allowed for both.

The standard should be updated to explicitly state that the voltage ride-through curves are to be interpreted as voltage vs time duration as is stated in IEEE 2800. This is to ensure that there is no incorrect interpretation that these curves are “envelope” curves. This could be done by adding a new note to explicitly call out the voltage vs time duration interpretation of the curves.

Alignment with FERC Directive for IBR Registration: BPS-connected/non-BES IBRs should be applicable to this standard, as it aligns with the FERC order activities and the on-going NERC Registration effort to incorporate the non-registered BPS-connected IBRs that are owned/operated by the new proposed Category 2 GO and GOP entities. Exclusion of these BPS-connected resources would significantly limit the ability to ensure that all BPS-connected IBRs have adequate voltage and frequency ride-through requirements during BPS/BES disturbances.

Alignment with NERC Glossary Definitions for IBRs: Creating a new definition for “inverter-based resources” is not aligned with the on-going IBR standard related work throughout NERC. By creating a new definition, it seems counter-productive to have a unique definition of IBRs and IBR units under the different NERC standards. Having all standards aligned to the new core NERC Glossary definition for IBRs will make all this standard development work, execution of the standards, and compliance activities more efficient for all entities involved.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

IEEE-2800: PRC-029 and IEEE-2800 do not have any contradictory requirements. Requirements within the NERC PRC-029 address the scope of the SAR and assigned directives from FERC Order No. 901. While some language between this draft aligns with IEEE-2800, NERC Standards are mandatory and enforceable requirements; in contrast to IEEE-2800.
Rules of Procedure regarding Standards Development: The team has been advised that NERC Standards cannot rely on information external to the Standard or would be in violation of the NERC Rules of Procedure.
Frequency: Alignment with IEEE-2800 regarding frequency exemptions would directly contradict assigned FERC directives. In Order No. 901, FERC directed NERC to determine whether the ride-through standard should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements, and only for voltage ride through performance for those existing IBRs that are unable to modify their settings without physical modification of equipment. See Order No. 901 at P 193. The drafting team determined that such an exemption was appropriate and it is included in Requirement R4. The drafting team does not have sufficient data at this time to determine whether additional frequency-based exemptions are appropriate and consistent with the overall reliability goals of Order No. 901. The drafting team does believe additional monitoring would be appropriate to determine how many entities would be affected by such an exemption and whether such an exemption would be consistent with overall Bulk-Power System reliability. To the extent such monitoring suggests that further exclusions would be appropriate, a future drafting team could make those changes in an expeditious manner. The affected entities could work with

ERO Enterprise staff to address any compliance-related concerns in the interim. For this draft, however, the drafting team is pursuing a more conservative approach in line with the specific exemptions identified in Order No. 901. **Applicability Section** – This section has been modified to reflect the current IBR definition as well as the approved changes to registration within the NERC Rules of Procedure. These modifications are consistent with changes to the applicability section within PRC-028 and PRC-030. **IBR Definitions**: While the previous definition for IBR was approved, it included the term IBR Unit, which was not approved and did not have an acceptable resolution to industry and the team. As such the language was considered to be unenforceable. The teams were advised to remove usage of unapproved terms until a clear path forward with the definitions could be assured. Project 2020-06 is moving forward with another version of a definition of IBR that removes the embedded usage of another term. The next drafts of Milestone 2 related projects, including PRC-029, include this new term as proposed by 2020-06. Additional definitions for parts within an IBR plant/facility will be developed by projects associated with Milestone 3 as determined by those teams. Further, regarding sub-BES IBR: the applicability section has been modified to include the registration criteria within the recently approved changes to the NERC Rules of Procedures. The team had been advised to hold on usage of specific language until the changes were approved.

Colin Chilcoat - Invenergy LLC - 6	
Answer	
Document Name	
Comment	

Thank you for the opportunity to provide comments and for your work on this project. Invenergy provides the below comments for the Drafting Team to consider:

R1: In response to industry comments, the SDT indicated that Requirement R5 from Draft 1 was removed, but it appears the phase-angle jump requirements have simply been reinserted under Requirement R1 in this second draft. As drafted, a facility is expected to ride-through fault-initiated switching events regardless of the magnitude of voltage phase angle change. Consider that positive sequence phase angle change cannot be accurately measured during a fault occurrence and clearance. We propose the assessment of ride-through performance during fault occurrence, clearance, and recovery be based only on the voltage ride-through criteria in Attachment 1 Table 1 and Table 2.

We recommend reverting the “Voltage (per unit)” columns of Table 1 and Table 2 back to their first draft state to remain consistent with Tables 11 and 12 of IEEE 2800.

R2.1.3: The decimal place is missing from “95 per unit.”

R2.2: Consider more clearly defining “maximum capability.” As an alternative, R2.2 could state, “…each IBR shall exchange current, up to the total sum of the nameplate current rating of online IBR units in the plant to provide voltage support…”

R2.3.1: Consider removal of this requirement. The time it should take a facility to restart current exchange following blocking seems irrelevant if the other ride-through performance requirements are being met.

Attachment 1: Note 11 from Attachment 1 should be removed. There are many equipment protection settings that are near instantaneous to protect against current or voltage surges that far exceed the equipment's maximum rating. A power electronic switch could burn out in a matter of micro-seconds due to such a surge, before any tripping decision could be made if the filtering length must be at least 16.6 milliseconds.

R3: We recommend reverting the "System Frequency (Hz)" columns of Table 3 back to its first draft state to remain consistent with Tables 15 of IEEE 2800.

The Consideration of Comments document seemed to indicate that the drafting team intended to respond to our previous comment regarding the expansion of the frequency ride-through range, but none was provided. The proposed 6-second frequency ride-through capability requirement for the ranges of 61.8Hz to 64Hz and 57Hz to 56Hz does not align with the requirements on the rest of the BES and would expose synchronous generators to dangerous variations in frequency. Can the drafting team cite more specific reasoning or data to support the expansion of the frequency ride-through capability requirement to the range of 64Hz to 56Hz, well beyond the IEEE 2800-2022 standard frequency ride-through requirement and the capabilities of many legacy IBRs?

R4: We recommend the following revision to R4.

R4. Each Generator Owner and Transmission Owner identifying a facility with a signed interconnection agreement by the effective date of PRC-029-1 with known hardware limitations that prevent the facility from meeting ride-through criteria as detailed in Requirements R1, R2, and R3, and requires an exemption from specific ride-through criteria shall:

Exemptions in R4 should be based on the execution of the interconnection agreement rather than the in-service date of the facility. As drafted, facilities with executed interconnection agreements, but not yet in-service by the effective date of the standard may need to make significant equipment modifications and perform interconnection restudies to comply with requirements that did not become effective until after the interconnection agreement was executed.

Regarding the lack of frequency ride-through exemptions, the limited exception language in FERC Order 901 is not supported by any comments or other evidence in the record in the original NOPR proceeding, and therefore we believe this to be an inadvertent omission and unjustified application of Order 901 in the draft language of PRC-029-1. In fact, in the NOPR, FERC proposed to direct NERC "to develop new or modified Reliability Standards that would require Generator Owners and Generator Operators to ensure that their registered IBR facilities ride through system frequency and voltage disturbances **where technologically feasible**." The drafted frequency ride-through performance requirements are not technologically feasible for many legacy IBRs.

Further, in Order 901, FERC "encourage[s] NERC's standard drafting team to consider currently effective Reliability Standard PRC-024-3, Requirement R3 as an example for establishing registered IBR technology exemptions." Requirement R3 of PRC-024-3, and the currently drafted version of PRC-024-4, allows for exemptions from both the frequency and voltage ride-through requirements due to equipment limitations.

Given the lack of a clear evidentiary record on this point, the drafting team should rely on the discretion FERC has always granted NERC when it comes to drafting and implementing practical Reliability Standards. Invenergy recommends Requirement R4 be amended to allow limited exemptions from specific voltage and frequency ride-through criteria for facilities with known hardware limitations that prevent the facility from meeting the ride-through criteria detailed in Requirements R1, R2, and R3.

Finally, Invenergy has concerns regarding the deviation of this project from its original goal of developing a standard that will require ride-through performance from *all* generating resources. As currently drafted, PRC-024-4 imposes fewer ride-through performance responsibilities on synchronous generators while allowing broader exemptions from its requirements than PRC-029-1. This undue discrimination permits scenarios in which both a synchronous generator and an IBR could trip offline due to the same system disturbance and only the IBR would be subject to a potential noncompliance, assuming the synchronous generator did not trip due to its protection system settings.

Implementation Plan: In its Consideration of Comments, the drafting team indicated that the Implementation Plan has been modified such that PRC-029-1 shall become effective on the first day of the first calendar quarter that is 12 months after the effective date of the applicable governmental authority's order approving PRC-028-1, however the Implementation Plan still lists an implementation timeframe of six months.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
Phase angle: The team has clarified language in R1 that there is a potential exemption for phase angle jumps greater than 25 degrees during non-fault switching events.
Attachment 1 tables: The tables have been adjusted as suggested.
R2.1.3: 95 per unit has been corrected to 0.95 per unit
R2.3.1: The team identifies this requirement as still needed to guarantee the IBR exits out of the current block mode when the high side of the main transformer voltage recovers back to the mandatory or continuous operation regions. Additionally, clarity has been added to the Technical Rationale.
R2.2: The team believes that the usage of maximum capability is clear.
R2.3: The team has included this specific instance of allowing current block mode which would cause momentary cessation and is not required to be used.
Attachment 1 notes: Some notes have been modified for clarity.
R3: Table 3 has been revised.

R4: Exemptions in R4 are based on confirmed expectations from FERC regarding the “existing” or “legacy” IBR. The team was advised that IBR that have not yet been built or Interconnected would not meet that expectation.

Frequency-based requirements exemptions: In Order No. 901, FERC directed NERC to determine whether the ride-through standard should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements, and only for voltage ride through performance for those existing IBRs that are unable to modify their settings without physical modification of equipment. See Order No. 901 at P 193. The drafting team determined that such an exemption was appropriate and it is included in Requirement R4. The drafting team does not have sufficient data at this time to determine whether additional frequency-based exemptions are appropriate and consistent with the overall reliability goals of Order No. 901. The drafting team does believe additional monitoring would be appropriate to determine how many entities would be affected by such an exemption and whether such an exemption would be consistent with overall Bulk-Power System reliability. To the extent such monitoring suggests that further exclusions would be appropriate, a future drafting team could make those changes in an expeditious manner. The affected entities could work with ERO Enterprise staff to address any compliance-related concerns in the interim. For this draft, however, the drafting team is pursuing a more conservative approach in line with the specific exemptions identified in Order No. 901.

Scope: The team identifies that additional measures to create performance-based measures for phase II of this project will determine any additional changes regarding synchronous generators.

Implementation Plan: The Implementation Plan has been modified to include bifurcated implementation information between capability-based elements and performance-based elements. Essentially this is a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. This approach allows for entities to align their PRC-028 and the performance-based aspects of their PRC-029 implementation. The time for capability-based implementation has been corrected to 12 months as identified.

Maozhong Gong - GE - GE Wind - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

-In R1, suggest the phase jump measurement to align to 2800 definition i.e.,Sub-cycle-to-cycle

-In Attachment 2, frequency ride through table is different with 2800. Suggest to align to 2800, otherwise the OEMs need to design for different specs.

-For R4.1, 12 months is not sufficient for documenting the supporting information for hardware limitation. Recommend a 2-year period for the exception documentation.

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. Additional information has been included in the Technical Rationale regarding phase jump measurements. Table 3 has been revised. The 12 month implementation plan for documenting known hardware-based limitations is considered reasonable for known/existing IBR.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	
PRC-029 R 2.1.3 should be 0.95 per unit not 95 per unit. Figures 1 and 2 in Attachment 1 of PRC-029 should use the same scale on the horizontal axis, either log or linear. Please clarify point 10 of attachment 1 of PRC-029: “The facility may trip for more than four deviations of the applicable voltage at the high-side of the main power transformer outside of the continuous operation region within any 10 second time period.” The Implementation Plan should be extended to 36 months to allow for monitoring equipment to be installed at sites completed before PRC-029 becomes enforceable, to demonstrate performance and compliance with the standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. **R2.1.3**: 95 per unit has been corrected to 0.95 per unit. **Attachment 1**: The logarithmic scale has been removed from Figure 1. **Attachment 1 note #9 (previously note #10**): provides an exemption to allow for tripping when more than four deviations outside of the continuous operation region. **Implementation Plan**: The Implementation Plan has been modified to include bifurcated implementation information between capability-based elements and performance-based elements. Essentially this is a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. This approach allows for entities to align their PRC-028 and the performance-based aspects of their PRC-029 implementation.	

Kinte Whitehead - Exelon - 3	
Answer	
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please refer to the responses to EEI.	
Chance Back - Muscatine Power and Water - 5	
Answer	
Document Name	
Comment	
I support NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please refer to the responses to NSRF.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	

AEPC only has minor concerns with PRC-024-4; however, in our opinion, PRC-029-1 still needs some work before we can recommend approval. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	
Document Name	
Comment	
It is imperative that the standard drafting teams for this project as well as the 2021-04 (PRC-002 and PRC-028) and 2023-02 (PRC-030 vs PRC-004) assure a coherent way of addressing the inclusion and exclusion of IBRs in current and upcoming standards. The following comments are applicable to PRC-029-1 The definition for Inverter Based Resource (IBR) was approved by industry in April under Project 2020-06. We do not agree with inserting the uncapitalized version of IBR into 4.2 Facilities section because it is unbounded and insufficient to identify the Facilities applicable to this Standard, as required in the Rules of Procedure (Appendix 3a, Standard Processes Manual). Furthermore, these definitions are the foundation of several ongoing projects in response to FERC Order 901, where FERC "directs NERC to submit new or modified Reliability Standards that address specific matters pertaining to the impacts of IBRs on the reliable operation of the BPS." The purpose section of PRC-029-1 refers to Inverter-Based Resources (IBRs) (capitalized, defined term) whereas the facilities section uses the uncapitalized version. Section 4.2.2: What IBR Registration Criteria are we referring to? Are we referring to the Category 2 GO/GOP facilities that are still awaiting a FERC decision? This section is not consistent with project 2021-04.	

For requirements R1 through R4, it is unclear which facilities are being referred to. Suggest rewording to “facilities identified in Section 4.2” or adding a sentence to 4.2 to indicate “For the purpose of this standard, the term “Applicable facilities” refers to the following:”. However, as stated above, it is unclear what facilities are included in the IBR Registration Criteria.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
IBR Definitions: While the definition for IBR was approved, it included the term IBR Unit, which was not approved and did not have an acceptable resolution to industry and the team. As such the language was considered to be unenforceable. The teams were advised to remove usage of unapproved terms until a clear path forward with the definitions could be assured. Project 2020-06 is moving forward with another version of a definition of IBR that removes the embedded usage of another term. The next drafts of Milestone 2 related projects, including PRC-029, will include this new term as proposed by 2020-06. Additional definitions for parts within an IBR plant/facility will be developed by projects associated with Milestone 3 as determined by those teams.
sub-BES IBR: the applicability section has been modified to include the registration criteria within the recently approved changes to the NERC Rules of Procedures. The team was advised to hold on usage of specific language until the changes had been approved.
Plant/facility: The terminology has been changed to IBR to coincide with the new proposed definition for IBR. Additionally, this section has been modified to include the registration criteria within the recently approved changes to the NERC Rules of Procedures. The team was advised to hold on usage of specific language until the changes had been approved.

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

Duke Energy offers the following Comments for Draft 2 of PRC-024 and PRC-029 - see Duke Energy, EEI and NAGF comments below.

PRC-024-4 Comments

1-Duke Energy recommends the following R2 word omission be rectified:

R2. Each Generator Owner and Transmission Owner shall…which it is applied “to” trip within…

PRC-029-1 Comments

EEI COMMENTS

Duke Energy agrees with and supports EEI filed comments as summarized below - see official EEI filed comments for additional detailed comments and proposed resolution(s):

1-The Standard attempts to redefine the approved definition of IBR by adding VSC-HVDC systems after the IBR definition was approved by the industry. EEI does not support: (a) expansion of the definition of IBRs beyond what was recently approved by the industry, since there is no technical justification for adding VSC-HVDC and, (b) the SAR did not include adding VSC-HVDC systems to this project. For these reasons, we ask that the definition of IBR not be expanded, and that the DT submit a technical justification for adding VSC-HVDC systems to the applicability section of this Standard, rather than redefining an approved definition in a footnote.

2-The Standard adds TOs to this Standard solely to address VSC-HVDC systems although: (a) no technical justification has been provided, and (b) these systems were not identified in FERC Order No. 901, the SAR, or in the Applicability Section of this proposed Reliability Standard.

3-EEI is concerned with the inclusion of requirements that are not clearly defined or set by multiple registered entities (i.e., TP, PC, RC, or TOP). This situation creates: (a) regulatory confusion and places IBR-GOs in a position where they may need to comply with any number of entities without clearly defining who is responsible, (b) IBR-GOs will have reporting obligations to multiple entities because no single entity is identified as being responsible, and (c) none of the entities identified (i.e., TP, PC, RC, or TOP) are identified within the Applicability section of this proposed Reliability Standard. This situation will likely create confusion and places considerable regulatory burden on the IBR-GOs and requires resolution and additional clarification.

4-Throughout this Reliability Standard there is use of: (a) non-glossary terms (i.e., active power vs. Real Power) where glossary terms are available and should be used and (b) glossary terms are used but not capitalized (e.g., reactive power vs. Reactive Power). Greater efforts should be made to use NERC Glossary terms where appropriate and capitalize those terms, as required.

5-Ride-through Definition:

EEI does not support the proposed definition for “Ride-through” as proposed because it is too vague and contains no defined limits, as proposed. We recommend the following changes: Reference EEI filed comments for this item.

6-Applicability Section:

(a) Footnote 1: EEI does not support adding TOs that own VSC-HVDC systems because it was not a scope item and is therefore not included in the scope of this SAR.

(b) Footnote 1 conflicts with Footnote 2 which defines VSC-HVDC as an IBR, which is not in alignment with the approved definition of an IBR.

(c) Footnote 2: EEI does not support Footnote 2 because it expands the definition of IBRs beyond what was recently approved by the industry, noting the expansion of IBRs to include VSC-HVDC.

(d) There was no technical justification for adding VSC-HVDC and the SAR did not include adding VSC-HVDC systems to this project.

For these reasons, we ask that the definition of IBR not be expanded through footnotes and suggest that the DT submit a technical justification for adding VSC-HVDC systems to the applicability section of this Standard, rather than redefining an approved definition in a footnote.

To address our concerns related to Footnotes 1 & 2, we suggest that if VSC-HVDC systems are to be classified as IBRs, then the approved definition should be pulled by NERC and resubmitted with those resources added to the definition and subsequently resubmitted to the industry for approval. Alternatively, VSC-HVDC systems could be defined separately, and that definition submitted to the industry for approval. In both cases, a technical justification should be provided to the industry that defines the issues and risks to BPS reliability that VSC-HVDC systems pose.

EEI suggests that if the DT believes certain IBR capabilities as identified under Requirement R2 need (or may need) to be specified then the DT should identify the entity who should be responsible among the four identified (i.e., TP, PC, RC or TOP); add them to the applicability section of this Reliability Standard; and add clear requirements and adjust the reporting obligations for the IBR-GO under Requirement R4.

7-Requirement R1 & R2:

EEI does not agree with the inclusion of Transmission Owners because they would only have an obligation under this Reliability Standard if VSC-HVDC systems were included. Given we do not support the inclusion of VSC-HVDC systems without a technical justification and modified SAR, we ask Transmission Owners be removed from Requirement R1.

8-Measures M1 & M2:

EEI is concerned that M1 & M2 contains measures that are overly prescriptive and provide little discretion to IBR-GOs in demonstrating their compliance with Requirements R1 and R2. As written, M1 and M2 appear to align more with a Requirement than a Measure (see official EEI filed comments for additional detailed comments and proposed resolution(s)).

9-Requirement R3 & R4: EEI does not support the inclusion of Transmission Owners within Requirements R3 & R4 for the same reasons identified above.

DUKE ENERGY COMMENTS

Additionally, Duke Energy provides the following additional comments:

10-Amend Standard to include GO specific and comprehensive responsibilities and identify functional entity required to approve exemption(s). 11-R3 does not provide specific Measure information in the Requirement – amend; as stated above, this action must provide definitive compliance guidance for GOs. 12-R4: Language does not allow for frequency exemptions (voltage exemptions allowed) – amend Requirement to allow for frequency exemptions. 13-R4.2.1 Amend language to require Regional Entity to respond within X calendar days. 14-R3: Amend language as follows: …"and suggest similar changes be made to M2" and M3. 15-R2.1.3: Requirement is duplicative with VAR-002 Reactive/Voltage support – consider removing. 16-Duke Energy recommends the word "ensure" be removed from all Requirements and specific Requirement language obligations be inserted to identify compliance. Use of the word "ensure" results in global compliance guidance that is not auditable unlike specific compliance Requirement(s). 17-Measurement M1: Consider including a standard Prerequisite Section in Standard that validates design and operation is such that each facility adheres to Ride-through requirements 18-M4/R4.3 – Resolve 30 calendar days vs. 90 calendar days conflict or clarify differences. Also, add "calendar" days to R4.3. **NAGF COMMENTS** Finally, Duke Energy agrees with and supports NAGF filed comments summarized below - see official NAGF filed comments for additional detailed comments and proposed resolution(s): 19-Consider removing Applicability 4.2.2 section, IBR Registration Criteria. 20-R2.5 requires clarity – revise narrative to state that active power shall be restored when "the voltage at the high-side of the main power transformer returns to the Continuous Operating Region".

Likes 0	
Dislikes 0	

Response
Thank you for your comments. **PRC-024-4** **R2:** The errata has been corrected.

PRC-029-1
IBR Definitions: While the definition for IBR was approved, it included the term IBR Unit, which was not approved and did not have an acceptable resolution to industry and the team. As such the language was considered to be unenforceable. The teams were advised to remove usage of unapproved terms until a clear path forward with the definitions could be assured. Project 2020-06 is moving forward with another version of a definition of IBR that removes the embedded usage of another term. The next drafts of Milestone 2 related projects, including PRC-029, will include this new term as proposed by 2020-06. Additional definitions for parts within an IBR plant/facility will be developed by projects associated with Milestone 3 as determined by those teams. Further**,** regarding sub-BES IBR: the applicability section has been modified to include the registration criteria within the recently approved changes to the NERC Rules of Procedures. The team was advised to hold on usage of specific language until the changes had been approved.
Transmission Owner: The transmission owner has been removed from PRC-029.
Other Performance Requirements: The language related to having evidence of other performance requirements was considered necessary for a situation where an entity receives requirements from a planner or operator that would contradict PRC-029 requirements. The team included this as a means of allowing the GO to follow requirements if needed by planners/operators and not be in violation of PRC-029 requirements. Planners and operators are not required to provide other performance requirements and are not applicable to this Standard. The language reads that as long as an entity is able to demonstrate that deviations from PRC-029 performance are due to other requirements provided by **any** of the listed entities, that the GO would not be in noncompliance.
Active Power: The terms have been replaced with those from the glossary.
Ride-through definition: The definition for Ride-through has been revised.
Applicability Section – footnotes: The footnotes have been revised to address the above changes.
Measures: the measures are now written to provide specific examples of evidence needed for compliance. Further the implementation plan has been revised to bifurcate between capability-based elements and performance-based elements. Essentially this is now a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. This will allow entities to align their PRC-028 and the performance-based aspects for PRC-029 compliance.
R4 acceptance: Additional information has been provided to R4 to clarify the acceptance expected. Requirements cannot be written towards Regional Entities. As written, an entity who submits the documentation as required and responds to additional requests as required would be compliant. An entity would not be determined to be noncompliant while the CEA (previously Regional Entity) processes that submittal.
R2.1.3: There is no obligation or requirement for planners or operators to supply other performance requirements. The language related to having evidence of other performance requirements was considered necessary for a situation where an entity receives requirements from a planner or operator that would contradict PRC-029 requirements. The team included this as a means of allowing the GO to follow requirements as needed by any planners/operators and not be in violation of PRC-029 requirements.
"Ensure": Usage of the term "ensure" has been removed from requirements and measures as suggested.
M4: Calendar days have been corrected as identified.
NAGF: Please refer to responses to NAGF

sub-BES IBR: the applicability section has been modified to include the registration criteria within the recently approved changes to the NERC Rules of Procedures. The team was advised to hold on usage of specific language until the changes had been approved.
R2.5: Language to allow different ramp rate requirements from planners/operators is already included. Also, for legacy equipment that cannot meet the requirements within PRC-029 due to hardware-based limitations, this would be covered in R4. Finally, R2.5 only refers to ramp rates after recovery from the mandatory operation region or permissive operation region to the continuous operation region.

Michael Goggin - Grid Strategies LLC - 5	
Answer	
Document Name	
Comment	

In the draft of PRC-029, R4 should be modified to allow existing resources with equipment limitations to obtain an exemption from the frequency ride-through requirements in R3, instead of only allowing an exemption from the voltage ride-through requirements in R1 and R2. This is necessary because some existing IBR generators cannot meet the stringent frequency ride-through requirements proposed in R3 without deploying significant hardware modifications or replacement, which goes against the intent of FERC Order 901.

The frequency ride-through requirements are particularly problematic for some existing wind generators. In the Technical Rationale document accompanying the PRC-029 draft, the drafting team notes that some wind generators are more sensitive to frequency deviations, writing that “All IBR resources (except for type 3 wind turbines) interface to the grid through fast switching of power electronics devices. These power electronic devices are much less sensitive to the transmission system frequency excursion than non-hydraulic turbine synchronous resources.”{C}[1] However, the drafting team then incorrectly concludes that “Therefore, IBR should be capable of riding through the increased proposed 6-second frequency ride-through requirement without risk of equipment damage or need for frequency protection to operate.” The Technical Rationale document does not offer any justification for its assumption that Type III wind turbines can meet the frequency ride-through requirements, despite noting that those turbines more directly interface with the grid and thus are more affected by frequency deviations than other IBRs.

In fact, many existing Type III wind turbines cannot meet the frequency ride-through requirements proposed in this draft of PRC-029. Those resources were designed to meet the reliability Standards and interconnection requirements that were in effect when they were placed in service, and were not designed to ride through frequency excursions of the magnitude and duration proposed in the draft Standard. Other types of existing IBR resources were also not designed to meet the proposed frequency ride-through requirements, and may similarly require extensive equipment modification or replacement to comply with R3.

Imposing a retroactive requirement on wind generators is particularly problematic as it is not typically feasible to retrofit existing wind turbines to increase their ability to ride through and withstand mechanical stresses due to frequency changes. In such cases, making existing equipment better able to withstand frequency changes would require full replacement or extensive modification of hardware, which would come at a significant, and sometimes prohibitive, cost. Frequency changes can impose mechanical stresses on highly sensitive elements in the wind turbine’s rotating equipment, including the generator, gearbox, the main shaft, and bearings associated with all of that equipment, and requiring such resources to ride through frequency changes they were not designed to operate through can damage that equipment. Subjecting Type III wind turbines to this damage may lead to increased outages or premature failure of these generators, potentially increasing reliability risks.

The easiest solution is to modify R4 to allow existing resources with equipment limitations toobtain an exemption from the frequency ride-through requirements in R3, which would make PRC-029 consistent with a long precedent of FERC interconnection requirements and NERC Standards only applying prospectively, including PRC-024. Retroactive requirements impose a much greater financial burden on the generator than prospective Standards, and set a bad precedent by unfairly penalizing generators that met all requirements that were in effect at the time they were installed. Retrofit or replacement costs are typically much greater than if the capability were installed at the plant to begin with. In some cases equipment needed for retrofits may not be available, particularly for models that have been discontinued or manufacturers that are no longer in business, potentially requiring the replacement of the entire wind turbine. Moreover, existing IBR generators typically sell their output at a fixed price under a long-term power purchase agreement, and unexpected retrofit or replacement costs cannot typically be recovered once a power purchase agreement has been signed. These unexpected and unrecoverable costs are far more concerning to lenders and other generation project financiers as they were not accounted for during the project's financing. As a result, retroactive requirements set a bad precedent by introducing regulatory uncertainty that makes future generation investment more uncertain and riskier, and likely more costly by forcing financiers to charge higher risk premiums.

Fortunately, these problems can be fixed by inserting "R3" into the list of permissible exemptions in R4, which would allow existing resources with equipment limitations to obtain an exemption from the frequency ride-through requirements in R3.

In the Technical Rationale document, the drafting team points to FERC's directive in Order No. 901 to justify not allowing existing resources to obtain an exemption from the frequency ride-through requirements in R3: "FERC Order No. 901 states that this provision would be limited to exempting 'certain registered IBRs from voltage ride-through performance requirements.' This is the reason that no similar provisions are included for exemptions for frequency or rate-of-change-of-frequency (ROCOF) ride-through requirements per R3."[2]

However, a contextual reading of Order No. 901 indicates FERC was focused on targeting equipment limitation exemptions at existing generators that would have to physically replace or modify hardware to comply with the Standard, and not focused on limiting such exemptions to voltage ride-through requirements. Paragraph 193 in its entirety, and particularly the first sentence, explain that FERC's intent was exempting existing resources that would have to physically replace or modify hardware: "we agree that a subset of existing registered IBRs –typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements directed herein." As a result, FERC continued by directing that "Any such exemption should be only for voltage ride-through performance for those existing IBRs that are **unable to modify their coordinated protection and control settings to meet the requirements without physical modification of the IBRs' equipment**."[3]

Allowing existing plants to apply for an equipment limitation exemption for the frequency ride-through requirements in R3 is necessary to ensure some existing generators do not have to physically replace or modify hardware. As a result, such an exemption is consistent with FERC's directive and intent in Order No. 901. As documented in the following footnote, there is ample precedent for NERC and standards drafting teams to exercise their technical expertise to craft Standards to align content and requirements with technical realities.[4]

Additional context in Order 901 further demonstrates that FERC intended for NERC to include an exemption for existing IBRs that cannot meet frequency ride-through requirements. At paragraph 190 in Order No. 901, FERC directed NERC to develop Standards that ensure resources "ride through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults." For many existing IBRs that cannot meet the proposed frequency ride-through requirements, tripping is necessary to protect the IBR equipment, similar to when synchronous generation resources use tripping as protection from internal faults. As a result, an exemption from R3 for existing resources is consistent with FERC's intent. Order No. 901 also directed NERC to consider the "PRC-024-3, Requirement R3 as an example for establishing registered IBR technology exemptions," and that exemption applies equally to voltage ride-through and frequency ride-through settings, further suggesting that FERC will allow certain IBRs an exemption from the frequency ride-through requirements.[5] Finally, Order No. 901 notes that in the notice of proposed rulemaking that led to the order, FERC "proposed to direct NERC to develop new or modified Reliability Standards that would require registered IBR facilities to ride through system frequency and voltage disturbances where technologically feasible."[6] FERC then adopted that very proposal,{C}[7] further demonstrating that FERC sought to direct NERC to only require frequency and voltage ride-through where technologically feasible.

It is likely that FERC Order No. 901 did not explicitly direct NERC to include frequency ride-through exemptions because FERC did not anticipate that NERC would adopt such an aggressive frequency ride-through requirement that some existing plants cannot meet. The drafting team even notes at page 7 in the Technical Rationale document that "The proposed 6-second time frame of the frequency ride-through capability requirement is beyond the IEEE 2800 standard frequency ride-through requirement and beyond frequency ride-through requirements for synchronous machines under proposed PRC-024-4." There is nothing in Order No. 901 that suggests that FERC was opposed to existing equipment exemptions for a frequency ride-through standard that was drafted after FERC issued Order No. 901 and is more stringent than FERC anticipated. A much more reasonable interpretation is that the logic FERC provided in paragraph 193 of Order No. 901 also applies to a frequency ride-through requirement that some existing resources cannot meet without physical modification or replacement of equipment. In fact, paragraph 193 makes clear that FERC's language focuses on an exemption from voltage ride-through requirements because "a subset of existing registered IBRs… may be unable to implement the voltage ride though performance requirements directed herein."

At the end of paragraph 193, FERC also explained that an exemption for existing resources would not harm reliability because "The concern that there are existing registered IBRs unable to meet voltage ride through requirements should diminish over time as legacy IBRs are replaced with or upgraded to newer IBR technology that does not require such accommodation." FERC's reasoning in paragraph 193 also applies to an exemption from frequency ride-through requirements, but particularly the conclusion that exempting existing plants does not cause reliability concerns and therefore should be allowed. The NERC drafting team's technical justification document explicitly explains that the frequency ride-through requirement is "to ensure the reliability of future grids with high IBR penetration,"{C}[8] based on concerns about declining inertia due to IBRs replacing synchronous resources. NERC and others have demonstrated that inertia and frequency response will remain more than adequate for the foreseeable future even following disturbances that are several times larger than current credible contingencies, and that higher IBR penetrations can actually significantly improve frequency stabilization following disturbances.[9]

As a result, there is no reliability concern from an exemption for the small number of existing resources that cannot meet the requirements without physical modification or replacement of equipment. Moreover, as FERC notes, these plants will replace that equipment anyway over time as legacy inverters fail or are replaced with more modern equipment for other reasons, and the draft standard requires replacement equipment to comply with the Standard. Utility-scale inverters installed at solar and battery installations typically come with warranties of 10 years or less,{C}[10] and those inverters are typically replaced at least once during the plant's lifetime. Many existing wind plants are also being repowered with newer turbines, often to allow the project to receive another 10 years of production tax credits after the initial 10 years of credits have been received. As a result, by the time the drafting team's concerns about inertia in a high IBR penetration future might materialize, the vast majority of IBRs that cannot meet the frequency ride-through requirements will have been replaced with new equipment that is not exempt.

Moreover, the drafting team's assumption that frequency deviations will be larger on a future low inertia power system is flawed. IBRs can provide fast frequency response, which stabilizes frequency in the initial seconds following a grid disturbance, before synchronous generators begin to provide their slower primary frequency response.[11] Thus fast frequency response provides a similar service to inertia in helping to arrest the change in frequency before primary frequency response is fully deployed, reducing the need for inertia.[12] Fast frequency response is easily provided by batteries due to their available energy, but can also be provided by curtailed wind or solar resources. Power systems with high IBR penetrations will tend to have some wind or solar curtailment in a significant share of hours. If allowed to do so, solar an battery resources with spare DC capacity behind the inverter can also temporarily exceed their interconnection agreement's AC injection limit to provide fast frequency response.

The replacement of inflexible synchronous resources with more flexible IBRs could also significantly improve primary frequency response, as NERC's modeling has demonstrated.{C}[13] NERC has also documented that only about 30% of synchronous generators provide primary frequency response, and only about 10% provide sustained primary frequency response.[14] Even with less inertia, the fast and accurate frequency response provided by IBRs will keep frequency more tightly controlled than the slow to nonexistent primary frequency response from synchronous generators. The replacement of large synchronous generators with smaller IBRs should also reduce the magnitude of frequency deviations following the loss of generators. If frequency response does begin to emerge as a concern, the more effective solution would be to enforce requirements on synchronous generators that are supposed to provide it but do not. If necessary, operators would alter real-time dispatch, as ERCOT and some island power systems occasionally do today, to ensure that inertia and fast frequency response are adequate to ensure under-frequency load shedding or generator tripping thresholds are not reached. Finally, grid-forming inverters are increasingly being deployed with battery storage and other IBR installations, further increasing the contributions of IBRs to stabilizing frequency.

At page 8 in the Technical Rationale document, the drafting team argues that "To compensate for the lack of inertia and short circuit contributions, [IBRs] should have wider tolerances for frequency and voltage excursions to meet the needs of future power systems with a higher percentage of IBR." The drafting team also argues that IBRs should have to ride-through much larger frequency deviations than synchronous resources because "Synchronous resources are more sensitive to frequency deviations than IBR resources." This logic is flawed for many reasons. Grid operators need all resources to ride through disturbances, and the contribution of a resource to inertia or short circuit needs is irrelevant to that need. Any concerns about resources' inertia and short circuit contributions are outside the drafting team's scope and authority, and should be addressed by other means (such as by increasing the deployment of grid-forming IBRs in the localized areas that have short circuit or stability concerns). It is also perverse for the drafting team to penalize IBRs for being less sensitive to frequency deviations than synchronous generators. As noted below, there are already grounds for FERC to reject this proposed standard due to undue discrimination against IBRs relative to the far more lenient requirements on synchronous generators under PRC-024, including an equipment limitation exemption for synchronous generators from the frequency relay setting requirement in PRC-024, and this only adds to those concerns.

In short, the drafting team's unfounded concerns about a future power system do not justify withholding an exemption to frequency ride-through requirements for existing IBR resources that will have been largely replaced by the time any concerns might materialize.

Finally, R4 equipment limitation exemptions should be allowed for resources with signed interconnection agreements as of the effective date of the Standard, instead of resources that are in-service as of that date. Resource equipment decisions are typically locked down at the time the interconnection agreement is signed, and a change in requirements after that point can require a costly change in equipment or settings that may also trigger a material modification and resulting interconnection restudies. The implementation plan for PRC-029 indicates that the effective date for the Standard will be the first day of the first quarter six months after FERC approval. Many resources take significantly longer than that to move from a signed interconnection agreement to being placed in service, so it makes more sense to allow R4 equipment limitation exemptions for resources that have a signed interconnection agreement as of the effective date of the Standard.

The current draft of the PRC-029 Standard is unworkable and will impose massive costs on some existing generators with no benefit for reliability. As explained above, the drafting team incorrectly ventures that "IBR should be capable of riding through the increased proposed 6-second frequency ride-through requirement without risk of equipment damage or need for frequency protection to operate," even after noting that some wind turbines use very different technology. NERC's rigorous standard development process exists to ensure that errors like this do not make it into final Standards, and the exceedingly low level of support for the initial draft and the major revisions in the current draft indicate that further revisions will likely be necessary. It takes time to fine tune highly technical requirements and vet them across the industry to avoid unnecessary and exorbitant costs for existing resources that cannot meet the standard. If the drafting team and NERC believe Order No. 901's deadlines do not provide enough time for further standard revisions and balloting periods to make the frequency ride-through requirement workable for existing resources, adding the letters "R3" to R4 to create an exemption for existing resources is the fastest and easiest way to address those concerns. For the reasons explained above, such an exemption does not pose any risk to reliability and is consistent with FERC's directive in Order 901.

Undue discrimination

A major concern with the Standards, as drafted, is that ride through performance is not required for synchronous generators under PRC-024-4, but it is for IBRs under PRC-029. PRC-024 simply requires protective relays to be set so they do not trip the generator within specified bounds, but it allows a resource to trip offline for other reasons. PRC-024-4 also allows a plant to trip if protection systems trip auxiliary plant equipment, per section 4.2.3. In contrast, PRC-029 requires IBRs to remain electrically connected and to continue to exchange current within the specified voltage and frequency bounds. Said another way, an IBR and a synchronous resource could both trip during the same disturbance, and the IBR would be in violation of PRC-

029 but the synchronous generator would not be in violation of PRC-024-4, as long as the synchronous generator did not trip due to the settings of its protection system.

To ensure grid reliability and resilience, all resources including IBRs and synchronous resources should ride through grid disturbances. The failure of synchronous generators to ride through grid disturbances threatens grid reliability as much or more than the failure of IBRs, as synchronous resources are often producing at a higher level of output, are more typically relied on as capacity resources, and often take longer to come back online and ramp up to full output if they trip due to a disturbance.

FERC Order No. 901 directed NERC to treat IBR resources similarly to how NERC Standards treat synchronous generators, writing that the IBR Standard should "permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults."{C}[15] Allowing synchronous generators to trip but requiring IBRs to ride through the same or similar disturbance will be challenged at FERC as undue discrimination. Providing synchronous generators with an equipment limitation exemption from PRC-024's relay-setting requirements but not offering existing IBR resources an exemption from the far more stringent frequency ride-through requirements in PRC-029 is also undue discrimination.

This disparate treatment of IBRs versus synchronous generators is also at odds with the intent for this project that NERC stated in its February 2023 comments on the FERC proposed rulemaking that led to Order No. 901: "A comprehensive, performance-based ride-through standard is needed to assure future grid reliability. To that end, NERC re-scoped an existing project, Project 2020-02 Modifications to PRC-024 (Generator Ride-through), to revise or replace current Reliability Standard PRC-024-3 with a standard that will require ride-through performance from all generating resources."[16] FERC's Order No. 901 also noted NERC's statement that this project would require ride-through performance from all generating resources,[17] so a failure to require ride-through performance from synchronous generators is contrary to both NERC's and FERC's intent.

Providing an exemption in PRC-029 R4 for existing IBRs that cannot meet the frequency ride-through requirement in R3 will result in less disparity with the treatment of synchronous resources under PRC-024, and is therefore an essential step if NERC wants to reduce the risk of FERC rejecting the proposed standard due to undue discrimination against IBRs.

{C}[1]{C} Technical Rationale, PRC-029-1 – Frequency and Voltage Ride-Through Requirements for Inverter-Based Generating Resources, at 8, https://www.nerc.com/pa/Stand/202002_Transmissionconnected_Resources_DL/2020-02_PRC-029-1_Technical_Rationale_Redline_to_Last_Posted_06182024.pdf ("Technical Rationale").

{C}[2]{C} *Id.*, at 10

{C}[3]{C} *Reliability Standards to Address Inverter-Based Resources*, Order No. 901, 185 FERC ¶ 61,042, P 193 (2023).

{C}[4]{C} For example, **Section 215(d)(2) of the FPA** requires FERC to give "due weight" to the technical expertise of the ERO when evaluating the content of a proposed Reliability Standard or modification to a Standard.

Order No. 733-A, P 11: "In this order, we emphasize and affirm that we do not intend to prohibit NERC from exercising its technical expertise to develop a solution to an identified reliability concern that is equally effective and efficient as the one proposed in Order No. 733."

Order No. 748, P 43: "In consideration of these ongoing efforts, we will not direct specific modifications to these Reliability Standards and, rather, accept NERC's commitment to exercise its technical expertise to study these issues and develop appropriate revisions to applicable Standards as may be necessary."

Order No. 896, P 36: "NERC may also consider other approaches that achieve the objectives outlined in this final rule. Further, as recommended by PJM, we believe there is value in engaging with national labs, RTOs, NOAA, and other agencies and organizations in developing benchmark events. Considering NERC's key role, technical expertise, and experience assessing the reliability impacts of various events and conditions, we encourage NERC to engage with national labs, RTOs, NOAA, and other agencies and organizations as needed."

Order No. 901, P 192: "We believe that, through its standard development process, NERC is best positioned, with input from stakeholders to determine specific IBRs performance requirements during ride through conditions, such as type (e.g., real current and/or reactive current) and magnitude of current. NERC should use its discretion to determine the appropriate technical requirements needed to ensure frequency and voltage ride through by registered IBRs during its standards development process."

{C}[5]{C} Order 901, P 193

{C}[6]{C} *Id.* at P 178.

{C}[7]{C} *Id.* at P 190.

{C}[8]{C} Technical Rationale at 7.

{C}[9]{C} East Interconnection Frequency Response Assessment with Inverter Based Resources, at 7 https://www.energy.gov/sites/prod/files/2018/07/f53/2.1.4%20Frequency%20Response%20Panel%20-%20Velummylum%2C%20NERC.pdf.

{C}[10]{C} Best Practices for Operation and Maintenance of Photovoltaic and Energy Storage Systems, at 55, https://www.nrel.gov/docs/fy19osti/73822.pdf.

{C}[11]{C}Fast Frequency Response Concepts and Bulk Power System Reliability Needs, https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf.

{C}[12]{C} Inertia and the Power Grid: A Guide Without the Spin, https://www.nrel.gov/docs/fy20osti/73856.pdf.

{C}[13]{C} East Interconnection Frequency Response Assessment with Inverter Based Resources, at 7 https://www.energy.gov/sites/prod/files/2018/07/f53/2.1.4%20Frequency%20Response%20Panel%20-%20Velummylum%2C%20NERC.pdf.

{C}[14]{C} https://www.nerc.com/pa/Stand/Project%20200712%20Frequency%20Response%20DL/FRI_Report_10-30-12_Master_w-appendices.pdf

{C}[15]{C} Order No. 901, at P190

[16]{C}https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Comments_IBR%20Standards%20NOPR.pdf, at 21-22.

[17]{C} Order No. 901, at P 185

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Frequency/R3/Attachment 2 Exemptions: In Order No. 901, FERC directed NERC to determine whether the ride-through standard should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements, and only for voltage ride through performance for those existing IBRs that are unable to modify their settings without physical modification of equipment. See Order No. 901 at P 193. The drafting team determined that such an exemption was appropriate and it is included in Requirement R4. The drafting team does not have sufficient data at this time to determine whether additional frequency-based exemptions are appropriate and consistent with the overall reliability goals of Order No. 901. The drafting team does believe additional monitoring would be appropriate to determine how many entities would be affected by such an exemption and whether such an exemption would be consistent with overall Bulk-Power System reliability. To the extent such monitoring suggests that further exclusions would be appropriate, a future drafting team could make those changes in an expeditious manner. The affected entities could work with ERO Enterprise staff to address any compliance-related concerns in the interim. For this draft, however, the drafting team is pursuing a more conservative approach in line with the specific exemptions identified in Order No. 901.
On the assertion of discrimination, IBR ride-through continues to be the problem, not synchronous generation ride-through. Synchronous generators have a hundred years of reliable performance, their limitations are well-known and understood, being physics-based, and their performance is predictable. Not so with IBRs which are being seen dropping off during minor system disturbances due to all manner of causes that have not been predicable.

Rhonda Jones - Invenergy LLC - 5

Answer	
Document Name	

Comment

Thank you for the opportunity to provide comments and for your work on this project. Invenergy provides the below comments for the Drafting Team to consider:

R1: In response to industry comments, the SDT indicated that Requirement R5 from Draft 1 was removed, but it appears the phase-angle jump requirements have simply been reinserted under Requirement R1 in this second draft. As drafted, a facility is expected to ride-through fault-initiated switching events regardless of the magnitude of voltage phase angle change. Consider that positive sequence phase angle change cannot be accurately measured during a fault occurrence and clearance. We propose the assessment of ride-through performance during fault occurrence, clearance, and recovery be based only on the voltage ride-through criteria in Attachment 1 Table 1 and Table 2.

We recommend reverting the "Voltage (per unit)" columns of Table 1 and Table 2 back to their first draft state to remain consistent with Tables 11 and 12 of IEEE 2800.

R2.1.3: The decimal place is missing from "95 per unit."

R2.2: Consider more clearly defining "maximum capability." As an alternative, R2.2 could state, "…each IBR shall exchange current, up to the total sum of the nameplate current rating of online IBR units in the plant to provide voltage support…"

R2.3.1: Consider removal of this requirement. The time it should take a facility to restart current exchange following blocking seems irrelevant if the other ride-through performance requirements are being met.

Attachment 1: Note 11 from Attachment 1 should be removed. There are many equipment protection settings that are near instantaneous to protect against current or voltage surges that far exceed the equipment's maximum rating. A power electronic switch could burn out in a matter of micro-seconds due to such a surge, before any tripping decision could be made if the filtering length must be at least 16.6 milliseconds.

R3: We recommend reverting the "System Frequency (Hz)" columns of Table 3 back to its first draft state to remain consistent with Tables 15 of IEEE 2800.

The Consideration of Comments document seemed to indicate that the drafting team intended to respond to our previous comment regarding the expansion of the frequency ride-through range, but none was provided. The proposed 6-second frequency ride-through capability requirement for the ranges of 61.8Hz to 64Hz and 57Hz to 56Hz does not align with the requirements on the rest of the BES and would expose synchronous generators to dangerous variations in frequency. Can the drafting team cite more specific reasoning or data to support the expansion of the frequency ride-through capability requirement to the range of 64Hz to 56Hz, well beyond the IEEE 2800-2022 standard frequency ride-through requirement and the capabilities of many legacy IBRs?

R4: We recommend the following revision to R4.

R4. Each Generator Owner and Transmission Owner identifying a facility with a signed interconnection agreement by the effective date of PRC-029-1 with known hardware limitations that prevent the facility from meeting ride-through criteria as detailed in Requirements R1, R2, and R3, and requires an exemption from specific ride-through criteria shall: Exemptions in R4 should be based on the execution of the interconnection agreement rather than the in-service date of the facility. As drafted, facilities with executed interconnection agreements, but not yet in-service by the effective date of the standard may need to make significant equipment modifications and perform interconnection restudies to comply with requirements that did not become effective until after the interconnection agreement was executed. Regarding the lack of frequency ride-through exemptions, the limited exception language in FERC Order 901 is not supported by any comments or other evidence in the record in the original NOPR proceeding, and therefore we believe this to be an inadvertent omission and unjustified application of Order 901 in the draft language of PRC-029-1. In fact, in the NOPR, FERC proposed to direct NERC "to develop new or modified Reliability Standards that would require Generator Owners and Generator Operators to ensure that their registered IBR facilities ride through system frequency and voltage disturbances **where technologically feasible**." The drafted frequency ride-through performance requirements are not technologically feasible for many legacy IBRs. Further, in Order 901, FERC "encourage[s] NERC's standard drafting team to consider currently effective Reliability Standard PRC-024-3, Requirement R3 as an example for establishing registered IBR technology exemptions." Requirement R3 of PRC-024-3, and the currently drafted version of PRC-024-4, allows for exemptions from both the frequency and voltage ride-through requirements due to equipment limitations. Given the lack of a clear evidentiary record on this point, the drafting team should rely on the discretion FERC has always granted NERC when it comes to drafting and implementing practical Reliability Standards. Invenergy recommends Requirement R4 be amended to allow limited exemptions from specific voltage and frequency ride-through criteria for facilities with known hardware limitations that prevent the facility from meeting the ride-through criteria detailed in Requirements R1, R2, and R3. Finally, Invenergy has concerns regarding the deviation of this project from its original goal of developing a standard that will require ride-through performance from all generating resources. As currently drafted, PRC-024-4 imposes fewer ride-through performance responsibilities on synchronous generators while allowing broader exemptions from its requirements than PRC-029-1. This undue discrimination permits scenarios in which both a synchronous generator and an IBR could trip offline due to the same system disturbance and only the IBR would be subject to a potential noncompliance, assuming the synchronous generator did not trip due to its protection system settings. **Implementation Plan:** In its Consideration of Comments, the drafting team indicated that the Implementation Plan has been modified such that PRC-029-1 shall become effective on the first day of the first calendar quarter that is 12 months after the effective date of the applicable governmental authority's order approving PRC-028-1, however the Implementation Plan still lists an implementation timeframe of six months.

Likes 0	

Dislikes 0	

Response

Thank you for your comment.
R1: the bullets under R1 are listed as possible exemptions and are not required to be used to demonstrate performance.
Attachment 1: Language regarding the usage of RMS voltage is provided in the notes for consistency.
R2.1.3: 95 per unit has been corrected to 0.95 per unit.
Attachment 1 notes: Some notes have been modified for clarity.
R3 – Table 3 has been revised.
R4: Exemptions in R4 are based on confirmed expectations from FERC regarding the "existing" or "legacy" IBR. The team was advised that IBR that have not yet been built or Interconnected would not meet that expectation.
Frequency/R3/Attachment 2 Exemptions: In Order No. 901, FERC directed NERC to determine whether the ride-through standard should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements, and only for voltage ride through performance for those existing IBRs that are unable to modify their settings without physical modification of equipment. See Order No. 901 at P 193. The drafting team determined that such an exemption was appropriate and it is included in Requirement R4. The drafting team does not have sufficient data at this time to determine whether additional frequency-based exemptions are appropriate and consistent with the overall reliability goals of Order No. 901. The drafting team does believe additional monitoring would be appropriate to determine how many entities would be affected by such an exemption and whether such an exemption would be consistent with overall Bulk-Power System reliability. To the extent such monitoring suggests that further exclusions would be appropriate, a future drafting team could make those changes in an expeditious manner. The affected entities could work with ERO Enterprise staff to address any compliance-related concerns in the interim. For this draft, however, the drafting team is pursuing a more conservative approach in line with the specific exemptions identified in Order No. 901.
On the assertion of discrimination, IBR ride-through continues to be the problem, not synchronous generation ride-through. Synchronous generators have a hundred years of reliable performance, their limitations are well-known and understood, being physics-based, and their performance is predictable. Not so with IBRs which are being seen dropping off during minor system disturbances due to all manner of causes that have not been predicable.
Implementation Plan: The Implementation Plan has been modified to include bifurcated implementation information between capability-based elements and performance-based elements. Essentially this is a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. This approach allows for entities to align their PRC-028 and the performance-based aspects of their PRC-029 implementation. The correction to 12 months has been addressed as identified.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

Southern Company supports NAGF comments.

Southern Company suggests that M1 be divided out to be clearer such as:

M1. Each Generator Owner and Transmission Owner shall have evidence of dynamic simulations, studies, or other evidence to demonstrate the design of each facility will adhere to Ride-through requirements, as specified in Requirement R1.

M1.1 Each Generator Owner and Transmission Owner shall have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) to demonstrate that the operation of each facility did adhere to Ride through requirements, as specified in Requirement R1.

M1.2 If the Generator Owner and Transmission Owner choose to utilize Ride-through exemptions that occur within the "must Ride-through zone" and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner and Transmission Owner shall also have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate that the facility failed to Ride-through during a phase jump of greater than or equal to 25 electrical degrees, and documentation from their Transmission Planner, Reliability Coordinator, Planning Coordinator, or Transmission Operator that a non-fault initiated switching event occurred.

Southern Company suggests adding an exemption for V/Hz to R3 like bullet 4 in R1.

R3 - Frequency Ride-Through Criteria

Southern Company recommends PRC-029-1 adopt Frequency Ride-Through Criteria (Attachment 2, Table 3 in draft 2) consistent with the IEEE2800 standard. Individual Regions should be allowed to adopt more stringent frequency ride-through standards based on their respective system needs and resource capabilities.

R4 – Exemptions

Any ultimate decision to disallow exemptions for requirements other than voltage, must be grounded in a thorough technical analysis of IBR OEM capabilities. NERC staff and standard drafting team participants have the necessary technical expertise to make these determinations. Additionally, there is ample precedent from prior Standard processes for FERC to defer to NERC on such technical issues. Finally, if the more stringent Frequency Ride-Through criteria in the current draft is preserved, this amplifies the need for consideration of existing equipment frequency ride-through exemptions. GOs and OEMs have not had adequate time to assess resource capabilities against requirements more stringent than IEEE2800.

Southern Company suggests that Requirement R4.3 be reworded to "...that replace the equipment causing the limitation, such that the limitation no longer exists, shall document and communicate..." The current wording is being interpreted that the only equipment that can be put back in place of a failed piece of equipment with a limitation is one without a limitation. Furthermore, R4.3.1 alludes that replacement of equipment with a limitation

must be made with equipment without limitation. This may not be possible due to uniqueness and limits associated with an existing facility design. There is no allowance for in-kind replacements. If one inverter burns down, there is no provision to replace it with an in-kind spare replacement unit. Note 7 on page 15 states that you only have to ride-through the voltage deviations if the frequency remains within the "must ride through zone". Doesn't there need to be a corresponding statement made on page 19? In other words, the standard should allow you to trip even if the frequency remained at a constant 60Hz if the voltage does not remain within the values in Attachment 1. Southern Company suggests that Requirement R4 also include identified "software limitations" in addition to hardware limitations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. **Frequency/R3/Attachment 2 Exemptions**: In Order No. 901, FERC directed NERC to determine whether the ride-through standard should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements, and only for voltage ride through performance for those existing IBRs that are unable to modify their settings without physical modification of equipment. See Order No. 901 at P 193. The drafting team determined that such an exemption was appropriate and it is included in Requirement R4. The drafting team does not have sufficient data at this time to determine whether additional frequency-based exemptions are appropriate and consistent with the overall reliability goals of Order No. 901. The drafting team does believe additional monitoring would be appropriate to determine how many entities would be affected by such an exemption and whether such an exemption would be consistent with overall Bulk-Power System reliability. To the extent such monitoring suggests that further exclusions would be appropriate, a future drafting team could make those changes in an expeditious manner. The affected entities could work with ERO Enterprise staff to address any compliance-related concerns in the interim. For this draft, however, the drafting team is pursuing a more conservative approach in line with the specific exemptions identified in Order No. 901. **Equipment replacement**: replacement for maintenance in-kind does not remove the limitation. Additional language was added to 4.3.1 to clarify this. **Frequency and may trip zone**: A footnote was added to R1 to clarify this instance "Except if this would occur during a frequency excursion. The active power response should recover in accordance with the primary frequency controller." The team identifies the inclusion for R1 to allow for tripping due to voltage excursions not simultaneously ongoing a frequency excursion. **Software limitations**: IBR, with software-based limitations alone, would not qualify for allowable exemptions per FERC Order 901.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	
Document Name	
Comment	

TEPC does not have any comments for PRC-024-4. TEPC agrees with EEI's comments regarding PRC-019-1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments, please see responses to EEI.	
Darcy O'Connell - California ISO - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee	
Answer	
Document Name	
Comment	

Ride-through Definition:

The ISO RTO Council Standards Review Committee (SRC) recommends that the drafting team provide a rationale for the proposed “Ride-through” definition, as it is not clear what benefits result from creating a formal definition for this term, and the definition that has been proposed contains ambiguous language.

First, use of the term “synchronized” in a definition intended to apply to IBRs could result in confusion because IBRs are generally considered to be asynchronous resources (though no mention of IBRs is made in the proposed definition). As a stand-alone term in the NERC glossary, the proposed definition could reasonably be interpreted to apply only to synchronous machines.

Second, the phrase “continuing to operate” is an inadequate description of desired performance – ride-through should include a concept of performance that is beneficial (or at the very least not detrimental) to overall grid reliability.

Third, the use of “Transmission System” potentially limits the applicability of the definition to only transmission-connected resources – the SDT may want to consider instead using a more general term such as “electric system” as was used in the proposed IBR definition.

Finally, defining the term “ride-through” may not be necessary at all. Meeting all of the requirements in PRC-029 essentially constitutes ride-through. Creating a separate defined term may just cause confusion, as the proposed definition does not clarify the desired (or required) performance associated with ride-through. The best option may be to leave the term undefined. If the SDT determines that a definition for Ride-though is an absolute necessity, the SRC proposes the following definition:

"Facilities, including all individual dispersed power producing resources, remaining connected to the electric system and continuing to operate in a manner that supports grid reliability throughout a System Disturbance, including the period of recovery back to a normal operating condition."

Comments on Proposed Requirements:

The language in PRC-029-1 Requirement R2, Part 2.1.3 that reads "…according to requirements if required by the [TP, PC, RC, or TOP]" seems awkward and redundant, as it seems that any requirements that exist will always be required. The SRC recommends that this language be changed to: "…according to TP, PC, RC, and TOP requirements, if any." Additionally, if the SDT continues to use a per unit metric for Part 2.1.3, the proposed "95 per unit" should be replaced with ".95 per unit . . . ."

Regarding PRC-029-1 Requirement R2, Part 2.2, it can be problematic to simply specify reactive/active power priority because not all priority implementations perform the same way. Part 2.2 does not really prohibit dropping active current to zero even for shallow voltage dips (e.g. 0.7-0.9pu), but seems to allow the TP, PC, RC, or TOP to specify the desired performance. The SRC requests that the SDT clarify whether this is the intended meaning, and revise Part 2.2 as necessary to clarify the intended meaning.

PRC-029-1 Requirement R2, Part 2.5 reads "…when the voltage at the high-side of the main power transformer returns from the mandatory operation region…." The SRC requests that the SDT clarify whether this was intended to read: "when the voltage at the high-side of the main power transformer returns **to the continuous operation region** from the mandatory operation region…."

In R2, Part 2.5 "available level (whichever is less)" should be revised to clarify whether "a lower post-disturbance active power level requirement" means lower than the pre-disturbance level or lower than the available level.

The SRC also notes that the phrase "…pre-disturbance or available level (whichever is lesser)…" in PRC-029-1 Requirement R2, Part 2.5 may be interpreted as allowing partial tripping/idling for an IBR facility. If the SDT's intent is that no individual wind turbines/inverters should be allowed to trip/idle, SRC recommends that this phrase be clarified with a footnote such as: "Reduction in available active power shall only be allowed due to a reduction in available source power (e.g. wind or solar irradiance). Reduction in available active power shall not occur due to tripping or idling of individual turbines or inverters within the IBR."

The SRC requests that the SDT clarify whether Requirement R1 should include an absolute rate of change of voltage criteria similar to the RoCoF criteria in PRC-029-1 Requirement R3. The SRC also requests clarification of whether the other bulleted exceptions listed in Requirement R1 apply during frequency excursions (in other words, the SRC requests clarification of whether ride through is required for frequency excursions even if the thresholds for V/Hz or phase angle jump specified in Requirement R1 are exceeded).

The SRC is concerned that the word “replaced” in PRC-029-1 Requirement R4, Part 4.3.1 may provide a pathway to circumvent the spirit of the standard (e.g., an entity could refurbish equipment and claim that its exemption should be maintained because equipment wasn’t “replaced”). The SRC recommends that “replaced, refurbished, or updated” be used instead. At the very least, the Technical Rationale should explain that documented limitations are expected to be eliminated whenever an IBR is re-powered, upgraded, or updated with significant re-investment.

In PRC-029-1, Attachment 1, Tables 1 and 2 use the term “operation region” while Figures 1 and 2 use the term “operating regions.” If the two terms are intended to have the same meaning, the SRC recommends that the same term be used in both locations (and throughout the standard). If the two terms are intended to have different meanings, the SRC recommends that the intended meanings be clarified.

In PRC-029-1, Attachment 1, item 7 references a “must ride-through zone” in Table 3 of Attachment 2. However, Table 3 of Attachment 2 does not explicitly specify a “must ride-through zone.” The SRC recommends that the SDT clarify whether Attachment 1, item 7 was intended to reference Figure 3 of Attachment 2, or otherwise clarify the intended meaning. The SRC also requests that the SDT clarify why Attachment 2 does not have a corollary item specifying that Table 3 is only applicable when voltage is within the “must ride-through zone” specified in Attachment 1. The SDT should update the Technical Rationale to clarify the intent: whether there is a need to verify or not to verify voltage status for the Table 3 Attachment 2.

The SRC notes that the Technical Rationale for PRC-029-1 contains what appears to be an extraneous “Must Ride-through” heading between the rational for R2.5 and the rationale for R3. The SRC recommends removal of this extraneous heading.

The SRC notes that the Technical Rationale for PRC-024-4 makes no explicit mention of the addition of type 1 and type 2 wind resources to PRC-024-4 and refers to restricting the applicability of PRC-024-4 to synchronous generators and synchronous condensers, which does not appear to be consistent with the posted redlines for PRC-024-4. The SRC recommends that PRC-024-4 and the Technical Rationale be harmonized to remove this discrepancy.

The applicability section for PRC-029-1 references “IBR Registration Criteria,” which presumably is intended to include IBRs connected to the BPS that are not considered BES Elements (consistent with the pending revisions to the registration criteria for IBRs). The SRC notes that the Technical Rationale is not very clear on the intent of this structure and requests that a more detailed explanation be included in the Technical Rationale.

Finally, the SRC notes that the addition of type 1 and type 2 wind resources to PRC-024-4 appears to be limited to facilities that meet the BES definition. The SRC requests that the SDT clarify whether this difference is intentional and, if it is, provide the rationale for the difference (such as if the revisions to NERC’s registration criteria are not intended to apply to non-BES type 1 or type 2 wind resources) and an explanation of whether the difference constitutes a potential gap that should be addressed.

Comments on Attachment 1: Voltage Ride-Through Criteria

Attachment 1 lists a minimum ride-through time of 1800 seconds for the continuous operation voltage region between 1.05 pu and 1.1 pu (<= 1.1 and >1.05) in Tables 1 and 2. The SRC requests that, consistent with IEEE 2800, an exception for 500 kV systems be allowed such that the minimum ride-

through time for 1.05 pu < voltage <= 1.1 pu for 500 kV systems is "Continuous," because the 1.05 pu < voltage <= 1.1 pu voltage range is within the normal operation range for some systems, such as PJM's system. In addition, in Figures 1 and 2, the SRC requests that the voltage pu values on Y-axis for the "Continuous Operating Region (1800 seconds)" be revised to be consistent with the values listed in Tables 1 and 2 (1.05 < and <= 1.1). Finally, the SRC generally supports incorporating as much of the IEEE 2800 language and parameters into PRC-029-1 as possible, and the SRC encourages the drafting team to lean on IEEE 2800 as much as is feasible.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. **Ride-through definition**: The definition for Ride-through has been revised. Usage of "Transmission System" has been removed. The term is considered necessary to tie the PRC-029 criteria to the PRC-030 analysis requirements. **IBR definition**: Project 2020-06 is moving forward with another version of a definition of IBR that removes the embedded usage of another term. The next drafts of Milestone 2 related projects, including PRC-029, will include this new term as proposed by 2020-06. Additional definitions for parts within an IBR plant/facility will be developed by projects associated with Milestone 3 as determined by those teams. **R2.1.3/R2.2:** The use of "if required" is not intended to only refer to a NERC requirement. The language related to having evidence of other performance requirements was considered necessary for a situation where an entity receives requirements from a planner or operator that would contradict PRC-029 requirements. The team included this as a means of allowing the GO to follow requirements if needed by planners/operators and not be in violation of PRC-029 requirements. Planners and operators are not required to provide other performance requirements and are not applicable to this Standard. The language reads that as long as an entity is able to demonstrate that deviations from PRC-029 performance are due to other requirements provided by any of the listed entities, that the GO would not be in noncompliance. **R2.1.3**: 95 pu has been corrected to 0.95 pu. **R2.5:** The modification has been made as suggested. Footnote 10 was added to clarify pre-disturbance power and available power. **Frequency and may trip zone**: A footnote was added to R1 to clarify this instance "Except if this would occur during a frequency excursion. The active power response should recover in accordance with the primary frequency controller." The team identifies the inclusion for R1 to allow for tripping due to voltage excursions not simultaneously ongoing a frequency excursion. **Equipment replacement**: replacement for maintenance in-kind does not remove the limitation. Additional language was added to 4.3.1 to clarify this. **Attachment 1**. Note 6 (previously note 7) has been updated to reflect the reference to Figure 3 rather than Table 3. **PRC-029 Technical Rationale**: The extraneous heading has been removed. **PRC-024 Technical Rationale**: The TR has been updated to include Type 1 and Type 2 Wind. **Attachment 1 Tables:** The tables have been corrected for consistency within the standard.	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

Electric Reliability Council of Texas, Inc. (ERCOT) joins the comments submitted by the ISO/RTO Council Standards Review Committee (SRC) and adopts them as its own. In addition, ERCOT submits the following comments.

ERCOT notes that the proposed Ride-through definition is unclear as to whether ride-through applies to partial trips (individual inverter or turbine trips). ERCOT believes ride-through should apply both to the IBR facility and to the individual IBR units and requests that this be made clear in any definition that may be adopted. If a defined term for ride-through is implemented, ERCOT recommends the use of a clarification modeled after the I4 inclusion ("dispersed power producing resources") in the BES definition, as detailed in the SRC's proposed definition:

"Facilities, including all individual dispersed power producing resources, remaining connected to the electric system and continuing to operate in a manner that supports grid reliability throughout a System Disturbance, including the period of recovery back to a normal operating condition."

Additionally, ERCOT has identified the following concerns with Requirement R1 as it is currently proposed:

1.) R1 does not clarify whether partial trips (individual IBR unit trips) would be allowed. ERCOT believes individual turbine/inverter trips should not be permissible under R1 and that R1 should clearly indicate that ride-through does not occur when individual turbines or inverters trip offline.

2.) Requirement R1's reference to "adhering" to requirements may create the mistaken impression that exceeding the minimum ride-through requirements is not allowed.

3.) Allowing an exclusion from Requirement R1 for equipment limitations should not result in a unit being exempt from complying with requirements that are not impacted by the limitation.

4.) The process for obtaining a documented limitation should be reviewed to ensure it is consistent with the directives that FERC included in its recent Order on EOP-011-2 in Docket No. RD24-5-000.

To address these issues, ERCOT recommends that Requirement R1 be revised to read as follows:

R1. Each Generator Owner or Transmission Owner shall ensure the design and operation is such that each facility ***meets or exceeds*** the Ride-through requirements, in accordance with the "must Ride-through3 zone" as specified in Attachment 1, except for the following: [Violation Risk Factor: High] [Time Horizon: Operations Assessment]

• The facility needed to electrically disconnect in order to clear a fault;

• ***The electrical system at the high-side of the main power transformer demonstrated characteristics that exceeded a*** documented ***and confirmed*** equipment limitation identified and communicated in accordance with Requirement R4; or

• The instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer and is initiated by a non-fault switching event on the transmission system; or

• The Volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

3 Includes no tripping associated with phase lock loop loss of synchronism; additionally, individual inverter or turbine tripping is not allowed.

ERCOT also recommends that Requirement R2, Part 2.1 and the surrounding language be reviewed and revised to clarify that the facility should continue to deliver the pre-disturbance level of current as appropriate, since power depends on voltage. In principle, during a disturbance active power should only reduce proportionally to voltage such that active current is consistent unless needed for frequency response. Reactive current should adjust as needed to support voltage (lead or lag as appropriate) up to its current limits. In general, the Requirement should neither incentivize entities to undersize inverters/converters nor impose onerous requirements to oversize this equipment. This lack of clarity may cause issues in enforcing this requirement and miss the reliability objective.

In addition, requiring a facility to deliver reactive power “according to its controller settings” is impractical and misses the objective. The requirement should be to ensure the proper response performance, as each facility operates according to its controller settings, even if those settings happen to be incorrect.

To address these issues, ERCOT recommends that the following portions of Requirement R2 be revised to read as follows:

R2. Each Generator Owner or Transmission Owner shall ensure the design and operation is such that the voltage performance for each facility adheres to the following during a voltage excursion, unless a documented equipment limitation exists in accordance with Requirement R4. [Violation Risk Factor: High] [Time Horizon: Operations Assessment]

2.1.1 Continue to deliver the pre-disturbance level of active ***current***, unless a different level of current is needed for frequency response.

2.1.2 Continue to deliver reactive ***current*** up to its reactive ***current*** limit, as appropriate to control voltage to within normal System Voltage Limits.

2.1.3 If the facility cannot meet 2.1.1 and 2.1.2 due to an apparent, active, or reactive current limit, when the applicable voltage is below .95 per unit and still within the continuous operation region, then preference shall be given to active or reactive current ***as well as allowed levels of reduction***, according to the Transmission Planner, Planning Coordinator, Reliability Coordinator, and Transmission Operator requirements.

2.6 Individual dispersed power producing resources must Ride-Through.

ERCOT appreciates the SDT's work on the purpose statement and believes that the purpose statement can be further clarified and simplified if it is revised to place the focus on PRC-029-1's intended effect of ensuring the units and facilities ride-through and perform as expected instead of focusing on "adhering" to requirements.

To achieve this objective, ERCOT recommends that the purpose statement be revised to read as follows: "To ensure that Inverter-Based Resources (IBRs) ride-through, during and after, defined frequency and voltage excursions while performing operationally as expected to support the Bulk-Power System (BPS)."

ERCOT is aware of an overarching concern that the RoCoF and phase angle jump requirements may be difficult to enforce for partial IBR tripping. Addressing this concern may be a matter of coordination of DFRs. If individual IBR units trip but the plant does not, DFRs may not trigger. PMUs would most likely not be fast enough to record the frequency or angle changes to validate performance. The appropriate NERC standard development teams should coordinate with each other to ensure that individual IBR unit trips trigger DFR recording.

ERCOT requests that the drafting team remove or provide additional explanation regarding the six-month gap between the PRC-028 effective date and the PRC-029 effective date in the Implementation Plan.

ERCOT also requests that the Implementation Plan be revised to clarify what constitutes being "in operation" (unit synchronization, full commercial operations, or some other milestone) for purposes of determining whether an IBR may be considered for a potential exemption under the Implementation Plan.

ERCOT encourages the SDT to review Requirement R4 and the Implementation Plan in their entirety and revise them as necessary to ensure they align with the directives regarding constraints and exemptions that FERC included in its recent Order on EOP-012-2 in Docket No. RD24-5-000. Each limitation should be confirmed before it is allowed to go into effect. ERCOT opposes the SDT's broad approach of allowing exemptions without some level of confirmation of the impact of the exemption, such as an evaluation of the reliability impact of the exemption by a PC, RC, TP, or TOP. ERCOT believes that it is important for reliability to specifically require that limitations be modeled and provided to the PC/RC/TP/TOP. This is important enough that it should be explicitly referenced in the standard and should be required if a limitation is to be allowed/confirmed. Otherwise, the PC/RC/TP/TOP will receive limitations that cannot be modeled. A description of a limitation may not allow assessments and may limit determination studies that can be performed, resulting in a gap that reliability entities are expected to address, when the burden should be on generator owners to remove the limitation or improve the model fidelity. ERCOT believes the SDT's proposed approach misses the objective of FERC's directive that the RC/PC/TP/TOP should ensure that reliability is maintained while any allowed exemptions are in effect. PRC-029-1 should incentivize facility owners to explore whether less expensive upgrades can remove limitations rather than passing the burden of unmodeled limitations onto reliability entities that do not have the means to secure the system against limitations they cannot model properly.

Likes 0	

Dislikes 0	

Response

Thank you for your comments.
Please refer to the responses to the ISO/RTO Council Standards Review Committee.
R2.5: If partial tripping prevents the IBR from returning to pre-disturbance active/available power level, it would result in potential noncompliance. Footnote #10 has been added for clarity.
IBR Definitions: While the definition for IBR was approved, it included the term IBR Unit, which was not approved and did not have an acceptable resolution to industry and the team. As such the language was considered to be unenforceable. The teams were advised to remove usage of unapproved terms until a clear path forward with the definitions could be assured. Project 2020-06 is moving forward with another version of a definition of IBR that removes the embedded usage of another term. The next drafts of Milestone 2 related projects, including PRC-029, will include this new term as proposed by 2020-06. Additional definitions for parts within an IBR plant/facility will be developed by projects associated with Milestone 3 as determined by those teams. Further**,** regarding sub-BES IBR: the applicability section has been modified to include the registration criteria within the recently approved changes to the NERC Rules of Procedures. The team was advised to hold on usage of specific language until the changes had been approved.
.

1) **Evaluation of plant performance:** The team is establishing plant/facility level ride-through requirements, consistent with the availability of disturbance monitoring data established within PRC-028. Further, Requirement R2 requires that the plant/facility must return to pre-disturbance values. Should the plant experience tripping of a portion of it's individual inverters, the overall plant would not be able to achieve compliance with R2. PRC-030 also includes mechanisms for the entities with a wider-area view to request data, analyze performance, and establish corrective action plans. Language in R1 has been modified to clarify that the ride through must ride-through zone is a minimum requirement and that the plant should not be designed or operated to deliberately trip or stop exchanging current at the boundary
2) **R1**: use of "adhering" has been modified
3) **Equipment replacement**: replacement for maintenance in-kind does not remove the limitation. Additional language was added to 4.3.1 to clarify this.
4) **R4**: Language was modified in R4 regarding submittal of information for acceptance. A footnote has been added clarifying acceptance criteria.

R2: The language in R2.1 referring to active/reactive power is consistent with IEEE2800 terminology.

R2.1.1/R2.1.2: The team advises to monitor the relevant quantities (for example: active current, active power, reactive current, reactive power, and the mode of operation). Additionally, a footnote was added to 2.1.1 to clarify returning to available power. Finally, refer to data requirements in PRC-028.

Purpose: The purpose statement has been revised.

Partial tripping: As addressed above.

Implementation Plan: Implementation Plan has been modified to include bifurcated implementation information between capability-based elements and performance-based elements. Essentially this is a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. This approach allows for entities to align their PRC-028 and the performance-based aspects of their PRC-029 implementation. Further, the disturbances identified by planners and operators within PRC-030, would trigger the request to hold data for demonstrating performance. Additional data requirements are established within PRC-030.

Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

IV. EPRI Comments on Draft 2 of PRC-029-1

The work and efforts of this standard drafting team are much appreciated. Thank you for considering EPRI comments on the Initial Draft as submitted previously. The new Draft 2 appears to be improved regarding internal consistency and alignment with requirements specified in voluntary industry standards, for example, IEEE 2800-2022. However, further improvements and alignment could be considered as follows:

General comments:

- Standard does not specify grid conditions for which ride-through requirements apply. During its lifetime, a plant may experience many different operational conditions, along with changes to the grid, and may fail to ride-through an event if plant was operating in a grid condition vastly different from that which it was designed for. The standard could include an exception for such situations based on leading industry practices, or a requirement for the TP, PC, etc. to specify such an exception.

- IEEE 2800-2022 allows for an exception for “self-protection” when negative-sequence voltage is greater than specified duration and threshold within continuous operation region. There is no such exception in draft PRC-029. Such an exception may be necessary for type III WTG based plants.

Ride-through definition:

- The term “synchronized” is used in the definition. The standard allows current blocking in the permissive operation region. One reason to allow current blocking was that injected current in permissive operation region may not be in synchronism with the grid because IBR has lost track of system voltage. The use of phrase “remaining synchronized” conflicts with the intent of current blocking allowance in the permissive operation region.

- The definition uses “Transmission System”. The NERC glossary of terms includes definition of “Transmission” and “System” but not “Transmission System”. Is the intent here is to refer to defined terms “Transmission” and “System”? At some point, this standard would apply to IBRs interconnecting to sub-transmission system. Definition of "Transmission" could include "sub-transmission" system. However, the SDT is encouraged to think about any unintended consequences of specifically calling out “Transmission System” in the definition.

• The definition states "… through the time-frame of a System Disturbance". The actual System Disturbance could be longer than specified time limits in this standard. So, the definition could specifically mention "within defined time limits". Perhaps replace "through the time-frame of a System Disturbance" with "within defined time limits".

• Consider adopting definition from IEEE 2800, which is from IEEE 1547, and well understood by the industry.

Purpose statement:

• Strike "as expected" and "defined" to read as follows: To ensure that Inverter-Based Resources (IBRs) adhere to Ride-through requirements as expected to support of the Bulk Power System (BPS) during and after defined frequency and voltage excursions.

Requirement R1:

Consider revising as following: Each GO and TO shall ensure design and operation operate is such that each facility adheres to Ride-through requirements… The same changes could be extended to other requirements.

Add "or" at end of first exception.

Requirement R2, Part 2.1

• Why is it necessary to specify performance requirement when voltage is in the continuous operation region? The standard remains silent on performance expectation for frequency ride-through requirements. For performance requirement for voltage ride-through mandatory operation region is also very brief. The intent of this standard is to focus on ride-through during voltage and frequency disturbances. If there is a desire to address performance then one option could be to simply state that performance shall be as specified by TP, PC, etc. That is in Part 2.1.3 anyway.

• Part 2.1.2: remove "and according to its controller settings". It is not incorrect but "according to its controller settings" inherently apply to all performance requirements.

Part 2.1.3: This is sub-part of 2.1 but does not read correctly. When sub-part 2.1.3 is read immediately after part 2.1, it reads "….in Attachment 1, each facility shall → if the facility cannot deliver…." Revise for better readability.

Furthermore, this requirement in IEEE 2800 was necessary and was tied to reactive power capability requirement as shown in Figure 8 of IEEE 2800. Given PRC-029 does not include reactive power capability requirements, perhaps PRC-029 could remain silent.

Replace "95 per unit" with "0.95 per unit"

Requirement R2, Part 2.2

• Part 2.2 applies at the high-side of the main power transformer. The IBR is required to exchange current, up to the maximum capability. How is the "maximum capability" of an IBR determined? There could be some explanation, perhaps with examples, in the technical rationale document.

The phrase "provide voltage support on affected phases during both symmetrical and unsymmetrical voltage disturbances" is confusing. It is understood that intent is to require to inject "unbalanced current" or "negative-sequence" current during asymmetrical faults. However, as written, injection of balanced reactive current into an unbalanced fault meets the requirement to provide voltage support on affected phases, in addition to unaffected phase. The standard does not prohibit voltage support on unaffected phases. The voltage support on unaffected phase is usually problematic. But the requirement, as written, does not prohibit this.

During a L-G fault, current in a faulted phase is dependent on transformer winding configuration. Does this requirement, unintentionally, specify specific transformer configuration?

During mandatory operation, voltage is abnormal and could be almost zero for close-in faults. As such, “current” over “power” is more appropriate. Power is faulted and unfaulted phases could be different as well. Replace active and reactive power with active and reactive current, respectively.

Requirement R2, Part 2.3.1

• Per language in attachment 1, permissive operation is allowed when line-to-ground or line-to-line voltage is below 10%. But per Part 2.3.1, IBR is required to restart current exchange when positive-sequence voltage enters continuous or mandatory operation region. This is conflicting. For example, for a line-to-ground fault on high-side terminals of main power transformer, the positive-sequence voltage would be more than 10%, i.e., in the mandatory operation region.

Requirement R2, Part 2.4

• The intent of this requirement is understood. However, if there are multiple plants in the area, then one plant misbehaving may cause overvoltage on high-side terminals of main power transformer of other plants in the area. Also, the post-fault dynamics greatly depend on system operating condition (peak, shoulder, off-peak, etc.) along with transmission outages, status of capacitor banks, etc. The Generator Owner usually does not have system data to evaluate post-fault system dynamics and to determine if plant’s behavior is or not a contributing factor to overvoltage.

Footnotes 5 and 7: Both footnotes are an exception to requirements. Are exceptions allowed in footnote?

Footnote 6: Uses “shall” and hence is a requirement. Move it to the main body of the standard. Additionally, uses “active power” and “reactive current”. Replace “active power” with “active current”.

Requirement R3

• Consider revising as following for better readability: Each GO and TO shall design and operate each IBR facility to Ride-through frequency excursion event where the System frequency remains within the “must Ride-through zone” according to Attachment 2 and the absolute rate of change of frequency (ROCOF) magnitude is less than or equal to 5 Hz/second.

• The proposed frequency ride-through requirement is more stringent than the applicable requirement in IEEE Std 2800-2022. The justification provided in the technical rationale is based on engineering judgement with no provided substantiating studies. Furthermore, the PRC-006 requires the design of UFLS program to keep frequency withing certain bounds. Requiring IBRs to ride-through a slightly more frequency deviation compared to frequency deviation band allowed in PRC-006 seems reasonable. However, the proposed frequency ride-through requirement is much more stringent. Consider aligning with IEEE Std 2800 frequency ride-through requirement as a minimum requirement and let regions specify more stringent requirements where justified.

• The standard does not allow exception for frequency ride-through requirements. For plants in commercial operation before the effective date of this standard, installed equipment (wind-turbine generator, inverter, etc.) was never tested to determine if it would be able to ride-through proposed frequency ride-through requirements. The SDT points to directive in FERC order 901 and states that order 901 does not allow exception for frequency ride-through. However, order 901 does not require frequency ride-through requirements as stringent as the ones proposed.

Footnote 8 Could be simplified as following: The ROCOF is an average rate of change of frequency over an averaging window of at least 0.1 second.

Requirement R4, Part 4.3

- Part 4.1 and 4.2 refer to exemption for a plant but part 4.3 refers to equipment in plant. If few of many wind-turbine generators in a plant are replaced, then plant still has limitation because most of the wind-turbine generators still have limited capability. Perhaps some clarification could be added that if all equipment with limitation is replaced then only exemption to facility does not apply.

Violation Severity Levels
R1, R2, and R3: The lower VSL for each of these requirements is for failure to demonstrate the capability to ride-through. Two reasons for which this could arise:
(1) Plant is capable to ride-through but is not demonstrated in design evaluation or interconnection studies.
(2) Plant is not capable to ride-through and is demonstrated in design evaluation or interconnection studies.

Reason (1) is not a problem for grid reliability, it is just that studies are not adequate to demonstrate ride-through capability, and hence lower VSL is justified. But reason (2) is not any different from a case in severe VSL where an entity fails to demonstrate that facility adhered to ride-through requirements (based on actual system disturbance event data).

Attachment 1
- Clarify that cumulative window, for voltage band where ride-through duration is 1800-second, is 3600-second. Also, consider clarifying that 1800-second ride-through duration is only applicable to nominal voltages other than 500 kV.
- Numbered item #3: states that applicable voltage is "… on the AC side of the transformer(s) that is (are) used to connect…..". Both sides of transformer are AC, one is on DC-AC converter side and another on AC grid side. As written, voltage on either side of transformer is applicable. Please clarify that applicable voltage is on AC "grid" side of the transformer.
- Numbered item #6: Consider revising as following - The applicable voltage for Tables 1 and 2 is identified as the voltage max/min of phase to neutral ground or phase to phase fundamental frequency root mean square (RMS) voltage at the high side of the main power transformer.
- Numbered item #8: The interpretation of ride-through curves/points needs further clarification. Would a wind-based IBR plant be required to ride-through an event where at t=0 voltage drops from nominal to zero, then @t=0.16 s voltage rises to 25%, @t=1.2 s voltage rises to 50%, @t=2.5 s voltage rises to 70%, @t=3 s voltage rises to 90%? The item (8) is also tied to item (12), where a combined "area" is stated. Does must ride-through zone represent an "area" (represented by deviation in voltage multiplied by time duration)?
- Numbered item 11: Please clarify if this statement applies to protection applied to high side of main power transformer only OR everywhere in the plant.

Attachment 2:
Table 3 - It should be considered to read like following: > 64
<= 64 and > 61.8

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<= 61.8 and > 61.5

<= 61.5 and > 61.2

<= 61.2 and >= 58.8

< 58.8 and >= 58.5

- Consider adding a statement that frequency ride-through requirements apply only when voltage is in the must ride-through zone.
- Numbered item 3: What is meant by control settings? Is the intent to state protection settings instead?

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
General:
Need statement on Grid Condition

The SDT Requirement R2 specifies the applicability of the standard for the specific system condition as per the TP, PC requirements based on the system wide studies. Operation outside of the normal system condition is not within the scope of this standard, which should be covered in other standards such as modeling and interconnection standard, e.g., FAC standard and/or MOD standards. And the SDT decided to keep silent on these IBR stability issues.

Need statement on self-protection for negative-sequence

Same to the above comment, the SDT determined that this issue is system dependent and should be covered the TP, PC studies. For legacy units which can't meet this requirement, the GO should follow Requirement R4 to request an exemption. Considering the fact that this standard is only applicable to GO, including this requirement may expand the applicability to other entities such as TP, PC, which is not aligned with IBR standard at this point. For the self-protection based on the negative-sequence current, the SDT suggested to propose a new SRA to address the IBR protection requirement.

Ride-through definition: The definition for Ride-through has been revised to reflect industry comments.
Purpose statement: The purpose statement has been revised to reflect industry comments.
R1: Language to "ensure" has been removed. The "or" was added to the first sub-bullet.
R2: The performance aspects of R2 are to assure adequate levels of ride-through characteristics during voltage excursions.

Need statement on "according to its controller settings
This requirement is aligned with the IEEE 2800-2022 7.2.2.2.
R2.1.3: There is no obligation or requirement for planners or operators to supply other performance requirements. The language related to having evidence of other performance requirements was considered necessary for a situation where an entity receives requirements from a planner or operator that would contradict PRC-029 requirements. The team included this as a means of allowing the GO to follow requirements as needed by any planners/operators and not be in violation of PRC-029 requirements. – The 95 per unit has been corrected to 0.95 per unit.

Need responses for all of R2.2 above.
The SDT agrees to add some examples to clarify the Maximum Capability and Negative Sequence Current during the unbalance fault condition in the next version of TR.
Need responses for all of R2.3.1 above.
Thanks for your comment. The SDT decided that, in the next version, a footnote or a note to Attachment 1 will be added to clarify that the permissive operation region is defined based on the positive sequence voltage below 0.1 pu. <u>This requirement is aligned with the FERC Order 901.</u>
Need responses for all of R2.4 above.
This requirement is intended to avoid a self-tripping caused by the control, the measurements from the tripping event will be used to analyze the tripping is caused by the IBR controller itself or the system condition. The scope of using measurements to determine the ride-through compliance is covered by the Standard PRC-030. If the tripping is related to the system condition, there will be no compliance violation.

Footnotes 5 and 7: Footnotes may be used to provide additional clarification or breakdown. This practice is allowable.
Footnote 9 (previously footnote 6): Need response
This footnote states that 'if required', which means this is not a mandatory requirement for the TP, PC to provide these requirements. The SDT deem real power is clear to the industry. More clarifications will be added to the next version of TR.
Need responses for all of R3 above.
The SDT disagrees with the proposed language, removing 'ensure' since the GO normally don't explicitly design the IBR plants. But the GO should ensure the design to meet the requirements.
Regarding the more stringent frequency requirement, please refer to the TR for more clarification.
Frequency/R3/Attachment 2 Exemptions: In Order No. 901, FERC directed NERC to determine whether the ride-through standard should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements, and only for voltage ride through performance for those existing IBRs that are unable to modify their settings without physical modification of equipment. See Order No. 901 at P 193. The drafting team determined that such an exemption was appropriate and it is included in Requirement R4. The drafting team does not have sufficient data at this time to determine whether additional frequency-based exemptions are appropriate and consistent with the overall reliability goals of Order No. 901. The drafting team does believe additional monitoring would be appropriate to determine how many entities would be affected by such an exemption and whether such an exemption would be consistent with overall Bulk-Power System reliability. To the extent such monitoring suggests that further exclusions would be appropriate, a future drafting team could make those changes in an expeditious manner. The

affected entities could work with ERO Enterprise staff to address any compliance-related concerns in the interim. For this draft, however, the drafting team is pursuing a more conservative approach in line with the specific exemptions identified in Order No. 901. **Footnote 12 (previously footnote 8)**: Need response The SDT decided to add more clarification to the next version of TR on the ROCOF calculation. **Equipment replacement**: replacement equipment that does not remove the limitation of the IBR (plant) does not satisfy the requirement. new language was added to 4.3.1 to clarify this. **VSLs:** Any root cause analysis for failing to demonstrate design evaluation would be facts and circumstances that are applied during the CMEP. Similar to determination of extent of condition, the facts would be considered by CMEP staff. **Attachment 1**: Need response The SDT decided to incorporate these suggestions in the next version as appropriate. **Attachment 2**: Need response The Table 3 has been modified. Please check the latest draft.	
Wes Baker - Silicon Ranch - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
General The SDT should consider specifying the grid conditions to which the ride-through requirements apply. The conditions should be bounded to some degree as the GO does not know the details of the transmission system and the range of operating conditions over the entire life of the plant. R1 PRC-029 does not have an exception for transient overvoltage. This implies that the plant must ride through an unbounded transient voltage magnitude, which is unreasonable. Power electronic devices are sensitive to voltage and current. Equipment vendors and plant designers need to have clear performance requirements to design their equipment and plants to meet and be able to protect their equipment from damage when conditions are outside of these performance requirements. The SDT should consider adding an exception for transient overvoltage similar to IEEE 2800-2022 Clause 7.2. R2 R2.1 Requirements for operating within the continuous operating range do not seem to be in scope with a ride-through standard. Additionally, these	

requirements are incomplete if the SDT intends to specify how the plant shall perform when voltage and frequency are within the continuous operating range. The SDT should consider removing R2.1.

R2.2

- Given that this requirement is at the IBR plant level, it is unclear how 'maximum capability' is defined. The SDT should consider clarifying in the standard what the IBR plant's 'maximum capability'technically refers to.
- During a mandatory operating range, it is more appropriate to use 'current' rather than 'power' since power is a function of voltage. The SDT should replace all references to 'power' with 'current' for voltage outside the continuous operating range.
- The response of the IBR during HVRT and LVRT is typically dictated by the inverterlevel control based on inverter terminal voltage. The inverter does not have information about the high side of the main power transformer voltage at the required time scale. Additionally, there are multiple transformers with different winding configurations (e.g., delta, wye, wye-grounded) between the POI/POM where the PRC-029 requirement applies and the inverter terminal where the control is implemented. Using positive and negative sequence reactive current consistent with IEEE 2800-2022 Clause 7.2 is more practical than the 'affected phases.' The key is that the IBR should regulate the positive sequence and negative sequence voltage. This is the resulting effect of the IBR injecting positive and negative sequence reactive current based on positive and negative sequence voltage, /';'['respectively, and is consistent with how a synchronous machine naturally responds to asymmetrical disturbance. The SDT should consider making the current injection requirements applicable at the inverter terminal and based on sequence components consistent with IEEE 2800-2022 Clause 7.2.

R2.3.1

The use of 'positive sequence voltage' with respect to the continuous and mandatory operating range is not consistent with the rest of the standard which uses max/min of phase-phase or phase-ground fundamental frequency RMS voltage. For consistency, the SDT should change positive sequence voltage to max/min of phase-phase or phase-ground fundamental frequency RMS voltage.

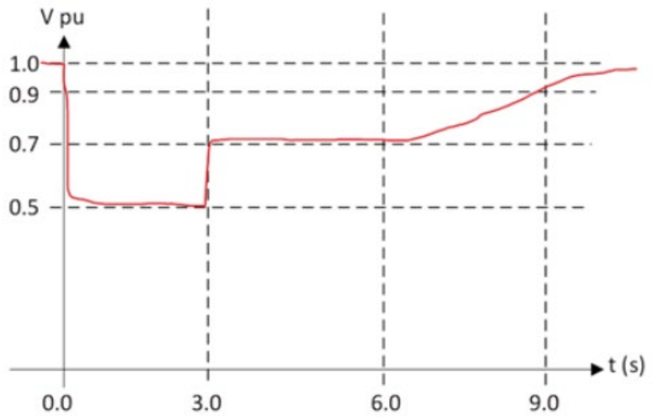
R2.4

The requirement, as written, may not be practical for assessing compliance/noncompliance for the GO. The voltage at the IBR plant would also depend on the grid, including neighboring plants. Therefore, the IBR plant itself is unlikely to cause the plant to exceed the high voltage thresholds but certainly may contribute to the overvoltage. The SDT should consider removing this requirement and lumping it together with R2.2, adding requirements to the response time consistent with IEEE 2800-2022 Clause 7.2. If the IBR actively regulates the positive and negative sequence voltage quickly, the effect is as desired and can be readily assessed for compliance.

R3

The frequency ride-through requirements are much more stringent than IEEE 2800-2022 Clause 7.3. The SDT should provide more justification, beyond what is described in the Technical Rationale, as to why this range of frequency ride-through is required. Additionally, the SDT should ensure that due diligence has been done with vendors of the various equipment to ensure that this requirement is reasonable, and achievable with available technology.

Attachment 1
Tables 1 and 2 and numbered item 8
By using voltage bands (e.g., 0.7 <= V < 0.9) and time durations this results in a much more stringent requirement than IEEE 2800-2022 Clause 7. The SDT should consider removing the voltage bands to align with IEEE 2800-2022 Clause 7. Take this example where the red is a fictitious voltage plot:



Comparison of standards:

- IEEE 2800 Clause 7:
  - V < 0.9 pu ~ 8 seconds
  - V < 0.7 pu ~ 3 seconds
  - There is not an interpretation where the IBR has to ride through this LVRT in

IEEE 2800 Clause 7.

- PRC029 :
  - 0.7 <= V < 0.9 pu ~ 5 seconds.
  - 0.5 <= V < 0.7 pu ~ 3 seconds.
  - PRC-029 as written implies the IBR has to ride-through.

Numbered item 11
The standard should not specify how protection functions must be implemented. Instead, it should describe the required performance. Further, this requirement implies that the plant must ride through an unbounded voltage magnitude, which is not reasonable. As written, this item does not allow for tripping caused by excessive transient over-voltage (TOV) events. Power electronic devices are sensitive to voltage and current. Equipment

vendors and plant designers need to have clear performance requirements to design their equipment and plants to meet and be able to protect their equipment from damage when conditions are outside of these performance requirements	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. Table 1 and Table 2 have been revised and the previous graphs associated to Table 1 and Table 2 have been removed. Additional voltage examples will be added to the next version of TR. The Note 11 is not to specify the protection setting, rather its purpose to avoid the instantaneous tripping without any filter.	

Comments received from LG&E/KU

<u>Questions</u>

1. Provide any additional comments for the Drafting Team to consider, if desired.

Comments:

All comments below pertain to PRC-029-1.

LG&E/KU agrees with the applicability concerns of EEI and suggests removing TOs and VSC-HVDC systems from this standard.

LG&E/KU also agrees with EEI that the requirements listing the TP, PC, RC, or TOP should clarify responsibility and include the responsible entity in the applicability of this standard. Alternatively, these listings may be sufficiently replaced with a requirement to adhere to applicable Facility interconnection requirements (e.g., “preference shall be given to active or reactive power according **to applicable Facility interconnection requirements**”).

The following additional comments are provided:

<u>Requirement R1</u>

Footnote 3 in Requirement R1 is unnecessary as the term “Ride-through” includes remaining synchronized.

The following edit should be made to Requirement R1 to clarify responsibility is only for Facilities (note “Facility” is a NERC defined term and should be capitalized) under the responsible entities ownership:

> … shall ensure the design and operation ~~is such that each~~ **of its IBR Facilities** ~~facility~~ adheres to Ride-through requirements~~, in accordance with the “must Ride-through[3] zone” as~~ specified in Attachment 1, except for …

The following edit is suggested for bullet 1 under Requirement R1:

The ~~facility~~ **IBR Facility** ~~needed to~~ electrically disconnect**s** in order to clear a fault; **or**

Measure M1

Measure M1 adds to the scope of Requirement R1. Measures should only describe how compliance with the associated Requirement will be assessed, not add to the scope of the Requirement itself. For example, Measure M1 strongly suggests that "dynamic simulations" and "studies" are the only acceptable forms of evidence for determining ride-through capability. However, Requirement R1 does not have any explicit requirement to perform analysis.

Measure M1 also states disturbance monitoring data is required to demonstrate adherence to Ride-through requirements. It is unclear what is required here since IBR Facilities will be online and operating normally most of the time. The most recent draft of PRC-030-1 already includes requirements for analyzing "Ride-through performance" in situations where the IBR Facility significantly reduces active power output (which would include tripping). It is more appropriate to analyze failed Ride-through than it is to provide immense quantities of data showing the IBR Facility is operating normally.

Measure M1 references only one of the exceptions listed under Requirement R1.

The following edit is suggested for Measure M1 (responsibility issues should also be addressed, as noted previously):

Each Generator Owner ~~and Transmission Owner~~ **shall** have evidence of ~~dynamic simulations, studies, or other evidence to demonstrate~~ **that** the design **and operation** of each **of its IBR Facilities** ~~facility will~~ adhere**s** to **the** Ride-through requirements~~, as~~ specified in **Attachment 1**~~Requirement R1. Each Generator Owner and Transmission Owner have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) to demonstrate that the operation of each facility did adhere to Ride-through requirements, as specified in Requirement R1. If the Generator Owner and Transmission Owner choose to utilize~~ **If failed** Ride-through **occurs for conditions exempted in Requirement R1** ~~exemptions that occur within the "must Ride-through zone" and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then~~ each Generator Owner ~~and Transmission Owner~~ **shall** ~~also~~ have evidence of **the conditions** ~~actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate that the facility failed to Ride-through during a phase jump of greater than or equal to 25 electrical degrees, and documentation from their Transmission Planner, Reliability Coordinator, Planning Coordinator, or Transmission Operator that a non-fault initiated switching event occurred~~.

Requirement R2

Requirement R2 addresses performance during the Ride-through conditions of Requirement R1 and should establish a clear link. There is also inconsistency in that Requirement R2 only exempts documented equipment limitations and none of the other exemptions in Requirement R1. The following edit is suggested for Requirement R2:

… shall ensure the design and operation ~~is such that~~ **of** the voltage performance ~~for~~ **of its IBR Facilities** ~~each facility~~ adheres to the following during **conditions requiring Ride-through** ~~a voltage excursion, unless a documented equipment limitation exists~~ in accordance with Requirement R**1**4.

Each part of Requirement R2 refers to the "voltage at the high-side of the main power transformer". Attachment 1 already states in item (6) that the applicable voltage is at the high-side of the main power transformer. Thus, each part of Requirement R2 should be condensed as follows:

> ~~While the voltage at the high-side of the main power transformer remains w~~Within the continuous operation region ~~as~~ specified in Attachment 1, ~~each facility~~ **IBR Facilities** shall:

Requirement R2 part 2.1.2 should be removed. Delivering reactive power "up to its reactive power limit and according to its controller settings" wouldn't appear to be anything other than normal operation.

Requirement R2 part 2.1.3 is clearly intended to mirror a similar requirement in IEEE 2800-2022 subclause 7.2.2.2. However it makes two errors, and unnecessarily restates the voltage is in the continuous operating region (Requirement R2 part 2.1 already includes this condition). Correct as follows:

> If the **IBR Facility** ~~facility~~ cannot deliver both active and reactive power due to a current limit or ~~reactive~~ **apparent** power limit, when the voltage is below **0.**95 per unit ~~and still within the continuous operation region~~, then preference shall be given to active or reactive power according to requirements ~~if required by~~ **of** the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

It is understood that the DT had "apparent power limit" in the first draft of this standard and has now replaced it with "reactive power limit" following comments. However, this is an error. The apparent power limit is a limit of the inverter and not the PPC as suggested in some of the comments. IEEE 2800-2022 correctly states the limit is "apparent" power. I.e., an inverter has an MVA limit and there may be times when the inverter is called on to produce more total MVA (MW and MVAR) than it is able to. It is in this case that the inverter must prioritize MW or MVAR.

The language of Requirement R2 part 2.2 is unnecessarily confusing. Attachment 1 already indicates the boundaries of the mandatory operating region and they are delineated by RMS voltages. Suggested simplification and clarification:

> ~~While voltage at the high-side of the main power transformer is w~~Within the mandatory operation region ~~as~~ specified in Attachment 1, ~~each~~ **an** IBR **Facility** shall **continue to** exchange current~~,~~ up to ~~the~~ **its** maximum **limit** ~~capability to~~ **and** provide voltage support**.**~~, on the affected phases during both symmetrical and asymmetrical voltage disturbances, either under[6]: •~~ **IBR Facilities shall operate in** ~~R~~**r**eactive power priority by default~~;~~**,** or~~•~~ **in** ~~A~~**a**ctive power priority if required by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Footnote 6 is unnecessary for this standard. Entities that wish to specify the magnitude of current injections during disturbances should do so in their Facility Interconnection Requirements.

Suggesting the following simplification of Requirement R2 part 2.3.1:

If an IBR Facility ~~facility~~ enters current blocking mode, it shall restart current exchange in less than or equal to five cycles of ~~positive sequence voltage~~ returning to the ~~a~~ continuous operation region or mandatory operation region.

Suggesting the following simplification of Requirement R2 part 2.5:

~~Each facility~~ IBR Facilities shall restore active power output to the pre-disturbance or available level ~~(~~, whichever is less~~er)~~, within 1.0 second ~~when the voltage at the high-side of the main power transformer~~ upon returning~~s~~ ~~from the mandatory operation region or permissive operation region (including operating in current block mode),~~ to the continuous operating region as specified in Attachment 1, unless the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specifies otherwise ~~requires a lower post-disturbance active power level requirement or requires a different post-disturbance active power restoration time~~.

Footnote 7 introduces confusion as it pertains to "frequency excursions" which is taken to mean conditions necessitating Ride-through. In this case, Requirement R3 and R4 would apply. Suggesting removal of this footnote.

Requirement R3

Suggesting the following simplification of Requirement R3 (to align with suggestions for Requirement R1):

… shall ensure the design and operation ~~is such that each facility~~ of its IBR Facilities adheres to Ride-through requirements ~~during a frequency excursion event whereby the System frequency remains within the "must Ridethrough zone" according to~~ specified in Attachment 2 ~~and~~ when the absolute rate of change of frequency (RoCoF)[8] magnitude is less than or equal to 5 Hz/second.

Measure M3

Measure M3 oversteps Requirement R3 similar to the M1/R1 discussion above. Suggested revision:

Each Generator Owner and Transmission Owner shall have evidence ~~of dynamic simulations, studies, or other evidence to demonstrate~~ that the design and operation of each of its IBR Facility ~~facility will~~ adheres to the Ride-through requirements~~, as~~ specified in Attachment 2 ~~Requirement R3. Each Generator Owner and Transmission Owner also have evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate the operation of each facility did adhere to~~ If failed Ride-through ~~requirements, as specified in Requirement R3, during each frequency excursion event measured at the high-side of the main power transformer~~ occurs for RoCoF magnitude greater than 5 Hz/second, each Generator Owner and Transmission Owner shall have evidence of the condition.

Requirement R4

Requirement R4 is unwisely linked to the effective date of PRC-029-1. This makes sense at the initial effective date, but it excludes IBR Facilities that come in-service *after* the effective date. Further, it doesn't address failure to meet *frequency* Ride-through requirements. It appears to unnecessarily call out hardware limitations when software limitations can also be problematic. Finally, it seems to imply an exemption process exists but does not say who can grant an exemption or what the requirements for exemption are (e.g., is it subject to approval of the technical documentation?). The following revision is suggested:

> **If a** ~~Each~~ Generator Owner ~~and Transmission Owner~~ identifi**ies**~~ying~~ **one of its IBR Facilities** ~~facility~~ ~~that~~ ~~is in-service by the effective date of PRC-029-1,~~ has known ~~hardware~~ limitations that prevent ~~the facility from~~ meeting ~~voltage~~ **the** Ride-through requirements ~~criteria as detailed in~~ **of** Requirements R1**, R2,** ~~and~~ **or** R**3**~~2~~, ~~and requires an exemption from specific voltage Ride-through criteria~~ **the Generator Owner** shall:

Below are suggested edits in various parts of Requirement R4 to align with the body of R4 suggested above:

> (4.1) Document ~~information supporting~~ the ~~identified~~ ~~hardware~~ limitation no later than 12 months ~~following the effective date of PRC-029-1~~ **after it is identified**.
>
> (4.1.2) Which aspects of voltage **or frequency R**~~r~~ide-through requirements ~~that~~ the IBR **Facility is** ~~would be~~ unable to meet and the capability of the equipment due to the limitation;
>
> (4.1.4) Supporting technical documentation ~~verifying~~ **explaining** if the limitation is due to hardware that needs to be physically replaced or ~~that~~ **if** the limitation can~~not~~ be removed by software updates or setting changes, and;
>
> (4.2) **Request an exemption from [whom?] by p**~~P~~rovid**ing**~~e~~ a copy of the information detailed in Requirement R4.1 to the applicable Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and to the Regional Entity no later than 12 months ~~following the effective date of PRC-029-1~~ **after the limitation is identified**.
>
> (4.2.1) Any response to additional information requested by the applicable Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), ~~and to the~~ **or** Regional Entity shall be provided ~~back to the requestor~~ within 90 days of the request.
>
> (4.3) Each Generator Owner and Transmission Owner with a previously submitted request for exemption that ~~replace the equipment causing~~ **corrects** the limitation shall document and communicate ~~such an equipment change~~ **the correction** to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the **correction** ~~equipment change~~.

(4.3.1) When ~~existing equipment is replaced~~ **an exempted Ride-through limitation is corrected**, the exemption ~~for that Ride-through criteria~~ no longer applies.

Much of Requirement R4 concerns an exemption process which is poorly defined. Other standards, including others currently being developed for IBRs due to FERC directives, have utilized language requiring “Corrective Action Plans” for certain failures. The DT should consider if alignment with these standards is appropriate and should revisit the scope of the SAR for this project. Regardless, the DT must address several key issues that it has created by introducing the exemption language:

- Who grants the exemption?
- How long does the approving entity have to grant or deny an exemption?
- Is an IBR Facility out of compliance if it has requested an exemption but the exemption has not yet been granted?
- Is there still a requirement to fix the issue if you have an exemption?
- What if an IBR Facility is unable to meet the Ride-through requirements without a significant investment (e.g., replacing every inverter with new models)?

Measure M4

Measure M4 should be substantially revised to reflect the concerns addressed in the comments above.

Attachment 1

Regarding Table 1 of Attachment 1, row 2 appears to use the incorrect operator and should be corrected as follows: “≤ 1.20 and > 1.1”.

Row 4 of Table 1 and Table 2 lists “Continuous” as a time where “∞” would be more appropriate.

It is recommended to remove footnotes 12 and 14 and place “May Ride-through Zone” directly into the table, e.g., “N/A (May Ride-through Zone)”.

Item (2)(b) of Attachment 1 references “hybrid plants consisting of photovoltaic (PV) and BESS” but does not address hybrid plants with other components. Item (4) says Table 2 applies to hybrid facilities with no wind. IEEE 2800-2022 clarifies that it does not apply to synchronous components of hybrid plants. PRC-029-1 needs to be more careful in its wording regarding hybrid plants.

Item (6) of Attachment 1 defines the applicable voltage as the high-side of the MPT and does not give the PC/TP/TO/etc. any flexibility to change that. Some entities with IEEE 2800-2022 requirements have adjusted the Reference Point of Applicability for Ride-through to the POI for various reasons (including that they may install monitoring equipment at that location rather than at the MPT). PRC-029-1 should not remove the flexibility of PC/TP/TO/etc. to alter the point of applicability.

Figure 1 of Attachment 1 uses the old "No-Trip Zone" label which is not used anywhere else in PRC-029-1.

Attachment 2

Regarding Table 3 of Attachment 2, "May trip" on rows 1 and 9 should be replaced with "N/A" for consistency with Table 1 and Table 2. It is unclear why the frequency values are unaligned (and exceed) IEEE 2800-2022 when the voltage Ride-through requirements of PRC-029-1 are aligned with IEEE 2800-2022. It is not prudent to exceed the requirements of IEEE 2800-2022 when 1) it already significantly exceeds PRC-024-3, and 2) it is recognized as an industry standard for utilities, developers, OEMs, etc.

Rows 5 and 6 of Table 3 have incorrect operators and row 6 includes an incorrect number (58.8 instead of 58.5).

Finally, item (1) of Attachment 2 defines the applicable frequency at the high-side of the MPT and does not give the PC/TP/TO/etc. any flexibility to change that. As noted above, some entities with IEEE 2800-2022 based requirements use the POI as the RPA for Ride-through capability.

Response
Thank you for your comments. **TO**: Transmission Owner has been removed from PRC-029. **Other Performance Requirements**: The language related to having evidence of other performance requirements was considered necessary for a situation where an entity receives requirements from a planner or operator that would contradict PRC-029 requirements. The team included this as a means of allowing the GO to follow requirements if needed by planners/operators and not be in violation of PRC-029 requirements. Planners and operators are not required to provide other performance requirements and are not applicable to this Standard. The language reads that as long as an entity is able to demonstrate that deviations from PRC-029 performance are due to other requirements provided by **any** of the listed entities, that the GO would not be in noncompliance. **Footnote 3:** Phase lock loop clarification was determined to be helpful to include. **Plant/facility**: The terminology has been changed to IBR to coincide with the new proposed definition for IBR. Additionally, this section has been modified to include the registration criteria within the recently approved changes to the NERC Rules of Procedures. The team was advised to hold on usage of specific language until the changes had been approved. **Measures:** the measures are now written to provide specific examples of evidence needed for compliance. Further the implementation plan has been revised to bifurcate between capability-based elements and performance-based elements. Essentially this is now a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. This will allow entities to align their PRC-028 and the performance-based aspects for PRC-029 compliance. **R1/R2**: R1 requires ride-through within the must Ride-through zone. R2 includes additional performance requirements beyond tripping/momentary cessation/failing to Ride-through.

R2.1.1/R2.1.2: The team advises to monitor the relevant quantities (for example: active current, active power, reactive current, reactive power, and the mode of operation). Additionally, a footnote was added to 2.1.1. Finally, refer to data requirements in PRC-028.
R2.1.3: 95 pu has been corrected to 0.95 pu.
R2.2: Language was revised for clarity
Previous footnote 6: See response to Other Performance Requirements above.
Implementation Plan: Implementation Plan has been modified to include bifurcated implementation information between capability-based elements and performance-based elements. Essentially this is a phased-in implementation plan whereas each entity will be required to respond to the full requirement over time. This approach allows for entities to align their PRC-028 and the performance-based aspects of their PRC-029 implementation. Further, the disturbances identified by planners and operators within PRC-030, would trigger the request to hold data for demonstrating performance. Additional data requirements are established within PRC-030.
R4 acceptance: Additional information has been provided to R4 to clarify the acceptance expected. Requirements cannot be written towards Regional Entities. As written, an entity who submits the documentation as required and responds to additional requests as required would be compliant. An entity would not be determined to be noncompliant while the CEA (previously Regional Entity) processes that submittal.
Attachments 1 and 2: Tables, figures, and notes have been reflected to address these comments and others from industry.

End of Report

Reminder

Standards Announcement

Project 2020-02 Modifications to PRC-024 (Generator Ride-through) | PRC-024-4 and PRC-029-1

Additional Ballots and Non-binding Polls Open through July 8, 2024

Now Available

Additional ballots for **Project 2020-02 Modifications to PRC-024 (Generator Ride-through)** and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Monday, July 8, 2024**.

The Standards Committee approved waivers to the Standard Processes Manual at their December 2023 meeting. These waivers were sought by NERC Standards staff for reduced formal comment and ballot periods. This will assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 901. *FERC Order 901 was issued under* Docket No. RM22-12-000 *on October 19, 2023*.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps
The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Manager of Standards Development, Jamie Calderon (via email) or at 404-960-0568 Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2020-02 Modifications to PRC-024 (Generator Ride-through) observer list” in the Titla and Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2020-02 Modifications to PRC-024 (Generator Ride-through) | PRC-024-4 and PRC-029-1

Formal Comment Period Open through July 8, 2024

Now Available

A 20-day formal comment period for **Project 2020-02 Modifications to PRC-024 (Generator Ride-through)**, is open through **8 p.m. Eastern, Monday, July 8, 2024.**

The Standards Committee approved waivers to the Standard Processes Manual at their December 2023 meeting. These waivers were sought by NERC Standards staff for reduced formal comment and ballot periods. This will assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 901. *FERC Order 901 was issued under* Docket No. RM22-12-000 *on October 19, 2023.*

The standard drafting team's considerations of the responses received from the previous comment period are reflected in these drafts of the standards and other documents.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps
Additional ballots for the standards and implementation plans, as well as the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **June 28 – July 8, 2024**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Manager of Standards Development, Jamie Calderon (via email) or at 404-960-0568 Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2020-02 Modifications to PRC-024 (Generator Ride-through) observer list” in the Description Box.

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/334)
Ballot Name: 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-024-4 AB 2 ST
Voting Start Date: 6/28/2024 1:41:54 PM
Voting End Date: 7/8/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 233
Total Ballot Pool: 271
Quorum: 85.98
Quorum Established Date: 7/8/2024 4:35:50 PM
Weighted Segment Value: 82.7

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	75	1	42	0.778	12	0.222	0	11	10
Segment: 2	8	0.7	6	0.6	1	0.1	0	0	1
Segment: 3	55	1	36	0.766	11	0.234	0	3	5
Segment: 4	14	0.9	9	0.9	0	0	0	1	4
Segment: 5	68	1	39	0.796	10	0.204	0	7	12
Segment: 6	46	1	26	0.722	10	0.278	0	4	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	5	0.4	4	0.4	0	0	0	1	0
Totals:	271	6	162	4.962	44	1.038	0	27	38

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		None	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner	Carly Miller	Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sempra - San Diego Gas and Electric	Mohamed Derbas	Jennifer Lapaix	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Negative	Third-Party Comments
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		None	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		None	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		None	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Abstain	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	American Municipal Power	Amy Ritts		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Juergen Bermejo		Abstain	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson	David Campbell	None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Chance Back		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Robin Berry		Affirmative	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments
5	PSEG Nuclear LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	Tennessee Valley Authority	Darren Boehm		Abstain	N/A
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
6	AEP	Mathew Miller		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Bonneville Power Administration	Tanner Brier		Abstain	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Great River Energy	Brian Meloy		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Luminant - Luminant Energy	Russell Ferrell		Affirmative	N/A
6	Manitoba Hydro	Brandin Stoesz		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer	Dane Rogers	Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 271 of 271 entries

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/334)
Ballot Name: 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-029-1 AB 2 ST
Voting Start Date: 6/28/2024 1:42:11 PM
Voting End Date: 7/8/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 228
Total Ballot Pool: 267
Quorum: 85.39
Quorum Established Date: 7/8/2024 4:38:40 PM
Weighted Segment Value: 35.45

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	74	1	15	0.306	34	0.694	0	15	10
Segment: 2	8	0.7	3	0.3	4	0.4	0	0	1
Segment: 3	54	1	12	0.267	33	0.733	0	4	5
Segment: 4	14	0.9	4	0.4	5	0.5	0	1	4
Segment: 5	67	1	15	0.319	32	0.681	0	8	12
Segment: 6	45	1	8	0.235	26	0.765	0	4	7
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	5	0.4	3	0.3	1	0.1	0	1	0
Totals:	267	6	60	2.127	135	3.873	0	33	39

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		None	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Negative	Comments Submitted
1	Avista - Avista Corporation	Mike Magruder		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner	Carly Miller	Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Third-Party Comments
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Negative	Comments Submitted
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Abstain	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
1	National Grid USA	Michael Jones		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Negative	Third-Party Comments
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas	Jennifer Lapaix	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Negative	Third-Party Comments
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer		Negative	Third-Party Comments
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		None	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		Negative	Comments Submitted
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Negative	Third-Party Comments
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		None	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Negative	Third-Party Comments
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Austin Energy	Tony Hua		Negative	Comments Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Third-Party Comments
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		None	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
4	Oklahoma Municipal Power Authority	Michael Watt		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Abstain	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	American Municipal Power	Amy Ritts		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Negative	Comments Submitted
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Third-Party Comments
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Negative	Third-Party Comments
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Third-Party Comments
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson	David Campbell	None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Negative	Third-Party Comments
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Chance Back		Negative	Comments Submitted
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments
5	PSEG Nuclear LLC	Tim Kucey		Negative	Third-Party Comments
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	Tennessee Valley Authority	Darren Boehm		Abstain	N/A
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
6	AEP	Mathew Miller		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Abstain	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Third-Party Comments
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Great River Energy	Brian Meloy		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Third-Party Comments
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Luminant - Luminant Energy	Russell Ferrell		Negative	Comments Submitted
6	Manitoba Hydro	Brandin Stoesz		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer	Dane Rogers	Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Negative	Third-Party Comments
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		Abstain	N/A
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party Comments
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted

Showing 1 to 267 of 267 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/334)
Ballot Name: 2020-02 Modifications to PRC-024 (Generator Ride-through) Implementation Plan AB 2 OT
Voting Start Date: 6/28/2024 1:42:27 PM
Voting End Date: 7/8/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 233
Total Ballot Pool: 271
Quorum: 85.98
Quorum Established Date: 7/8/2024 4:38:19 PM
Weighted Segment Value: 48.59

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	75	1	22	0.423	30	0.577	0	13	10
Segment: 2	8	0.7	5	0.5	2	0.2	0	0	1
Segment: 3	55	1	16	0.356	29	0.644	0	5	5
Segment: 4	14	0.7	5	0.5	2	0.2	0	3	4
Segment: 5	68	1	20	0.426	27	0.574	0	9	12
Segment: 6	46	1	11	0.314	24	0.686	0	5	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	5	0.4	3	0.3	1	0.1	0	1	0
Totals:	271	5.8	82	2.818	115	2.982	0	36	38

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		None	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner	Carly Miller	Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Negative	Comments Submitted
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Nazra Gladu		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas	Jennifer Lapaix	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Negative	Third-Party Comments
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Third-Party Comments
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		None	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		Negative	Comments Submitted
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Negative	Third-Party Comments
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		None	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
4	Austin Energy	Tony Hua		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		None	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
4	Oklahoma Municipal Power Authority	Michael Watt		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Abstain	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	American Municipal Power	Amy Ritts		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo		Abstain	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson	David Campbell	None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Invenergy LLC	Rhonda Jones		Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Negative	Third-Party Comments
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Manitoba Hydro	Kristy-Lee Young		Negative	Comments Submitted
5	Muscatine Power and Water	Chance Back		Negative	Comments Submitted
5	National Grid USA	Robin Berry		Affirmative	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	Tennessee Valley Authority	Darren Boehm		Abstain	N/A
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
6	AEP	Mathew Miller		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Abstain	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Third-Party Comments
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Great River Energy	Brian Meloy		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Luminant - Luminant Energy	Russell Ferrell		Negative	Comments Submitted
6	Manitoba Hydro	Brandin Stoesz		Negative	Comments Submitted
6	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer	Dane Rogers	Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		Abstain	N/A
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party Comments
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted

BALLOT RESULTS

Ballot Name: 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-024-4 | Non-binding Poll AB 2 NB
Voting Start Date: 6/28/2024 1:42:43 PM
Voting End Date: 7/8/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 211
Total Ballot Pool: 254
Quorum: 83.07
Quorum Established Date: 7/8/2024 4:55:08 PM
Weighted Segment Value: 76.51

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	71	1	35	0.778	10	0.222	14	12
Segment: 2	7	0.3	2	0.2	1	0.1	3	1
Segment: 3	52	1	29	0.744	10	0.256	7	6
Segment: 4	14	0.8	7	0.7	1	0.1	2	4
Segment: 5	63	1	32	0.78	9	0.22	10	12
Segment: 6	42	1	19	0.704	8	0.296	7	8
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0
Segment: 9	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	5	0.3	3	0.3	0	0	2	0
Totals:	254	5.4	127	4.206	39	1.194	45	43

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		None	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner	Carly Miller	Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas	Jennifer Lapaix	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		None	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Austin Energy	Lovita Griffin		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		None	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Tony Hua		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Abstain	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Bonneville Power Administration	Juergen Bermejo		Abstain	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson	David Campbell	None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Muscatine Power and Water	Chance Back		Affirmative	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A
6	AEP	Mathew Miller		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Abstain	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Great River Energy	Brian Meloy		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Luminant - Luminant Energy	Russell Ferrell		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer	Dane Rogers	Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Showing 1 to 254 of 254 entries

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BALLOT RESULTS

Ballot Name: 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-029-1 | Non-binding Poll AB 2 NB
Voting Start Date: 6/28/2024 1:43:04 PM
Voting End Date: 7/8/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 207
Total Ballot Pool: 251
Quorum: 82.47
Quorum Established Date: 7/8/2024 5:03:47 PM
Weighted Segment Value: 29.03

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	71	1	11	0.275	29	0.725	19	12
Segment: 2	7	0.2	0	0	2	0.2	4	1
Segment: 3	51	1	10	0.27	27	0.73	8	6
Segment: 4	14	0.8	4	0.4	4	0.4	2	4
Segment: 5	62	1	12	0.308	27	0.692	11	12
Segment: 6	41	1	5	0.2	20	0.8	7	9
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0
Segment: 9	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	5	0.4	3	0.3	1	0.1	1	0
Totals:	251	5.4	45	1.753	110	3.647	52	44

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		None	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner	Carly Miller	Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Comments Submitted
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Negative	Comments Submitted
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Abstain	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Abstain	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas	Jennifer Lapaix	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A
2	ISO New England, Inc.	John Pearson		Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		None	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		Negative	Comments Submitted
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		None	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
4	Austin Energy	Tony Hua		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		None	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
4	Oklahoma Municipal Power Authority	Michael Watt		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Abstain	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo		Abstain	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Decatur Energy Center LLC	Megan Melham		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	Enel Green Power	Natalie Johnson	David Campbell	None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Comments Submitted
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Muscatine Power and Water	Chance Back		Negative	Comments Submitted
5	National Grid USA	Robin Berry		Negative	Comments Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Comments Submitted
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Abstain	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Great River Energy	Brian Meloy		Negative	Comments Submitted
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Luminant - Luminant Energy	Russell Ferrell		Negative	Comments Submitted
6	Muscatine Power and Water	Nicholas Burns		Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer	Dane Rogers	Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Abstain	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted

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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

Draft 3 of PRC-029-1 is posted for a formal comment and additional ballot.

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023
25-day formal comment period and initial ballot	March 27 – April 22, 2024
15-day formal comment period and additional ballot	June 18 – July 8, 2024

Anticipated Actions	Date
15-day formal comment period and additional ballot	July 22 – August 12, 2024
Final Ballot	August 26 – September 6, 2024
Board adoption	October 8, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Ride-through: The entire plant/facility remaining connected to the Bulk Power System and continuing in its entirety to operate through System Disturbances.

The term Inverter-based Resource (IBR) refers to proposed definitions being developed under the Project 2020-06 Verifications of Models and Data for Generators. As of this posting, the proposed definition of an IBR is:

IBR: A plant/facility consisting of individual devices that are capable of exporting Real Power through a power electronic interface(s) such as inverter or converter, and that are operated together as a single resource at a common point of interconnection to the electric system. IBRs include, but are not limited to, plants/facilities with solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell devices.

A. Introduction

1. **Title:** **Frequency and Voltage Ride-through Requirements for Inverter-based Resources**
2. **Number:** **PRC-029-1**
3. **Purpose:** To ensure that IBRs Ride-through to support the Bulk Power System (BPS) during and after defined frequency and voltage excursions.
4. **Applicability:**
   - **4.1 Functional Entities:**
     - **4.1.1.** Generator Owner
   - **4.2 Facilities:**
     - **4.2.1.** The Elements associated with (1) Bulk Electric System (BES) IBRs; and (2) Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Effective Date: See Implementation Plan for Project 2020-02 – PRC-029-1

Standard-only Definition: None

B. Requirements and Measures

R1. Each Generator Owner shall ensure the design and operation is such that each IBR meet or exceed Ride-through requirements, in accordance with the "must Ride-through[1] zone" as specified in Attachment 1, except for the following: *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

- The IBR needed to electrically disconnect in order to clear a fault; or
- The voltage at the high-side of the main power transformer[2] went outside an accepted hardware limitation, in accordance with Requirement R4; or
- The instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer and is initiated by a non-fault switching event on the transmission system[3]; or
- The Volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

M1. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to Ride-through requirements, as specified in Requirement R1. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall retain evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) to demonstrate that the operation of each IBR did adhere to Ride-through requirements, as specified in Requirement R1. If the Generator Owner choose to utilize Ride-through exemptions that occur within the "must Ride-through zone" and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate that the IBR failed to Ride-through during a phase jump of greater than or equal to 25 electrical degrees, and documentation from their Transmission Planner, Reliability Coordinator, Planning Coordinator, or Transmission Operator that a non-fault initiated switching event occurred.

R2. Each Generator Owner shall ensure the design and operation is such that the voltage performance for each IBR adheres to the following during a voltage excursion, unless a documented hardware limitation exists in accordance with Requirement R4. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

[1] Includes no tripping associated with phase lock loop loss of synchronism

[2] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for IBRs. In case of IBR connecting via a dedicated Voltage Source Converter High Voltage Direct Current (VSC-HVDC), the main power transformer is the main power transformer on the receiving end.

[3] Current blocking mode may be used for non-fault initiated phase jumps greater than 25 degrees in order to prevent tripping.

2.1. While the voltage at the high-side of the main power transformer remains within the continuous operation region as specified in Attachment 1, each IBR shall:

2.1.1 Continue to deliver the pre-disturbance level of Real Power or available Real Power[4], whichever is less.[5]

2.1.2 Continue to deliver Reactive Rower up to its Reactive Power limit and according to its controller settings.

2.1.3 Prioritize Real Power or Reactive Power when the voltage is less than 0.95 per unit, the voltage is within the continuous operating region, and the IBR cannot deliver both Real Power and Reactive Power due to a current limit or Reactive Power limit, unless otherwise specified through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.2. While voltage at the high-side of the main power transformer is within the mandatory operation region as specified in Attachment 1, each IBR shall exchange current, up to the maximum capability to provide voltage support, on the affected phases during both symmetrical and asymmetrical voltage disturbances, either under[6]:

- Reactive Power priority by default; or
- Real Power priority if required through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.3. While voltage at the high-side of the main power transformer is within the permissive operation region, as specified in Attachment 1, each IBR may operate in current blocking mode if necessary to avoid tripping. Otherwise, each IBR shall follow the requirements for the mandatory operation region in Requirement R2.2.

2.3.1 If a IBR enters current blocking mode, it shall restart current exchange in less than or equal to five cycles of positive sequence voltage returning to a continuous operation region or mandatory operation region.

2.4. Each IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable high voltage thresholds and time

[4] "Available Real Power" refers to changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes of facility Real Power attributed to IBR tripping in whole or part.
[5] Except if this would occur during a frequency excursion. The Real Power response should recover in accordance with the primary frequency controller.
[6] In either case and if required, the magnitude of Real Power and reactive current shall be as specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

durations in its response as voltage recovers from the mandatory or permissive operation regions to the continuous operation region.

2.5. Each IBR shall restore Real Power output to the pre-disturbance or available level[7] (whichever is lesser) within 1.0 second when the voltage at the high-side of the main power transformer returns from the mandatory operation region or permissive operation region (including operating in current blocking mode) to the continuous operation region, as specified in Attachment 1, unless an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires a lower post-disturbance Real Power level requirement or requires a different post-disturbance Real Power restoration time through other mechanisms.[8]

M2. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to requirements, as specified in Requirement R2. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate that the operation of each IBR did adhere to performance requirements, as specified in Requirement R2, during each voltage excursion measured at the high-side of the main power transformer. In regard to R2.1.3, R2.2, and R2.5, the Generator Owner shall retain evidence of receiving such performance requirements, (e.g. email exchange, contract information) if the Transmission Planner, Transmission Operator, Reliability Coordinator, or Planning Coordinator has required the Generator Owner through other mechanisms to follow performance requirements other than those in Requirement R2 (e.g. ramp rates, Reactive Power prioritization).

R3. Each Generator Owner shall ensure the design and operation is such that each IBR meets or exceeds Ride-through requirements during a frequency excursion event whereby the System frequency remains within the "must Ride-through zone" according to Attachment 2 and the absolute rate of change of frequency (RoCoF)[9] magnitude is less than or equal to 5 Hz/second. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

M3. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to Ride-through requirements, as specified in Requirement R3. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate the operation of each IBR did adhere to Ride-through requirements, as specified in

[7] "Available Real Power" refers to changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes of facility Real Power attributed to IBR tripping in whole or part.

[8] Except if this would occur during a frequency excursion. The Real Power response should recover in accordance with the primary frequency controller.

[9] Rate of change of frequency (RoCoF) is calculated as the average rate of change for multiple calculated system frequencies for a time period of greater than or equal to 0.1 second. RoCoF is not calculated during the fault occurrence and clearance.

Requirement R3, during each frequency excursion event measured at the high-side of the main power transformer.

R4. Each Generator Owner identifying an IBR that is in-service by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting voltage Ride-through criteria as detailed in Requirements R1 and R2, and requires an exemption from specific voltage Ride-through criteria shall*:*[10] *Lower] [Time Horizon: Long-term Planning]*

4.1. Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1. This documentation shall include:

4.1.1 Identifying information of the IBR (name and facility #);

4.1.2 Which aspects of voltage Ride-through requirements that the IBR would be unable to meet and the capability of the hardware due to the limitation;

4.1.3 Identify the specific piece(s) of hardware causing the limitation;

4.1.4 Supporting technical documentation verifying the limitation is due to hardware that needs to be physically replaced or that the limitation cannot be removed by software updates or setting changes, and;

4.1.5 Information regarding any plans to remedy the hardware limitation (such as an estimated date).

4.2. Provide a copy of the information detailed in Requirement R4.1 to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA no later than 12 months following the effective date of PRC-029-1.

4.2.1 Any response to additional information requested by the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA shall be provided back to the requestor within 90 days of the request.

4.2.2 Provide a copy of the acceptance of an hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s).[11]

4.3. Each Generator Owner with a previously accepted limitation that replace the hardware causing the limitation shall document and communicate such a hardware change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the hardware change.

[10] The exemption requests for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

[11] Acceptance by the CEA is verification that the information provided includes all information listed in Requirement R4.1.

4.3.1 When existing hardware causing the limitation is replaced, the exemption for that Ride-through criteria no longer applies.

M4. Each Generator Owner submitting for an exemption for an IBR that is in-service by the effective date of PRC-029-1, shall have evidence of submission to the CEA consistent with the information listed in Requirement R4.1. Each Generator Owner shall have evidence of communicated copies of each submission in accordance with Requirement R4.2 and to the associated entities described in Requirement R4.2. Acceptable types of evidence for submittals include but are not limited to, meeting minutes, agreements, copies of procedures or protocols in effect, or email correspondence. Acceptable types of evidence for a hardware limitation may include but is not limited to documentation that contains study results, experience from an actual event, or manufacturer's advice. Each Generator Owner that receives a request for additional information under Requirement R4.2.1 shall have evidence of providing that information within 90 calendar days. Each Generator Owner that replaces hardware at an IBR that is directly associated with an accepted exemption and that hardware is the cause for the limitation, shall have evidence of communicating the hardware change to the associated entities described in Requirement R4.3 within 90 calendar days of the hardware replacement.

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.

1.2. Evidence Retention: 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.

- Each Generator Owner shall retain evidence with Requirements R1, R2, and R3 in this standard for 36 calendar months or the date of the last audit, whichever is greater.
- Each Generator Owner shall retain evidence with Requirement R4 in this standard for five calendar years or the date of the last audit, whichever is greater.

1.3. Compliance Monitoring and Enforcement 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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The Generator Owner failed to demonstrate the design capability of each applicable IBR to Ride-through in accordance with Attachment 1, except for those conditions identified in Requirement R1.	N/A	N/A	The Generator Owner failed to demonstrate each applicable IBR adhered to Ride-through requirements in accordance with Attachment 1, except for those conditions identified in Requirement R1.
R2.	The Generator Owner failed to demonstrate the design capability of each applicable IBR to adhere to performance requirements during voltage excursions, as specified in Requirement R2.	N/A	N/A	The Generator Owner failed to demonstrate each applicable IBR adhered to performance requirements during voltage excursions, as specified in Requirement R2.
R3.	The Generator Owner failed to demonstrate the design capability of each applicable IBR to Ride-through in accordance with Attachment 2.	N/A	N/A	The Generator Owner failed to demonstrate each applicable IBR adhered to Ride-through requirements in accordance with Attachment 2.
R4.	The Generator Owner with a previously communicated hardware limitation that replace the documented limiting hardware but failed to document and communicate	The Generator Owner with a previously communicated hardware limitation that replace the documented limiting hardware but failed to document and communicate	The Generator Owner with a previously communicated hardware limitation that replace the documented limiting hardware but failed to document and communicate	The Generator Owner failed to document complete information for IBR identified with known hardware limitations that prevent the IBR from meeting voltage

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and CEA more than 90 calendar days but less than or equal to 120 calendar days after the change to the hardware. OR The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 12 months but less than or equal to 15 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 90 days but less than or equal to 120 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.	the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 120 calendar days but less than or equal to 150 calendar days after the change to the hardware. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 120 days but less than or equal to 150 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.	the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 150 calendar days but less than or equal to 180 calendar days after the change to the hardware. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 150 days but less than or equal to 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.	Ride-through criteria as detailed in Requirements R1 or R2. OR The Generator Owner with a previously communicated hardware limitation that replace the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s),Reliability Coordinator(s), and CEA more than 180 calendar days after the change to the hardware. OR The Generator Owner failed to provide a copy to the applicable entities as detailed in Requirement R4.2 within 24 months after the effective date of Requirement R4. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan .

Version History

Version	Date	Action	Change Tracking
Initial Draft	3/27/24	Draft	
Draft 2	6/4/24	Revised following initial comment review	
Draft 3	7/22/24	Revised following additional comment review	

Attachment 1: Voltage Ride-Through Criteria

Table 1: Voltage Ride-through Requirements for AC-Connected Wind IBR [12]

Voltage (per unit)[13]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[14]	N/A
≥ 1.10	Mandatory Operation Region	1.0
> 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90	Mandatory Operation Region	3.00
< 0.70	Mandatory Operation Region	2.50
< 0.50	Mandatory Operation Region	1.20
< 0.25	Mandatory Operation Region	0.16
< 0.10	Permissive Operation Region	0.16

Table 2: Voltage Ride-through Requirements for All Other IBR

Voltage (per unit)[15]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[16]	N/A
> 1.10	Mandatory Operation Region	1.0
> 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90	Mandatory Operation Region	6.00
< 0.70	Mandatory Operation Region	3.00
< 0.50	Mandatory Operation Region	1.20
< 0.25	Mandatory Operation Region	0.32
< 0.10	Permissive Operation Region	0.32

[12] Type 3 and type 4 wind resources directly connected to the AC Transmission System.
[13] Refer to bullet #4 below.
[14] These conditions are referred to as the "may Ride-through zone".
[15] Refer to bullet #4 below.
[16] These conditions are referred to as the "may Ride-through zone".

1. Table 1 applies to type 3 and type 4 wind IBR or hybrid IBR that include wind, unless connected via a dedicated VSC-HVDC transmission facility.
2. Table 2 applies to all other IBR types not covered in Table 1; including, but not limited to, the following facilities:
    a. IBR, regardless of their energy resource, interconnecting via a dedicated VSC-HVDC transmission facility.
    b. Other IBR or hybrid IBR consisting of photovoltaic (PV) and BESS.
3. The applicable voltage for VSC-HVDC system with a dedicated connection to an IBR is on the AC side of the transformer(s) that is (are) used to connect the VSC-HVDC system to the interconnected transmission system.
4. The voltage base for per unit calculation is the nominal phase-to-ground or phase-to-phase transmission system voltage unless otherwise defined by the Planning Coordinator, Transmission Planner, or Transmission Owner.
5. The applicable voltage for Tables 1 and 2 is identified as the voltage max/min of phase-to-neutral or phase-to-phase fundamental root mean square (RMS) voltage at the high-side of the main power transformer.
6. Tables 1 and 2 are only applicable when the frequency is within the "must Ride-through zone" as specified in Figure 1 of Attachment 2.
7. At any given voltage value, each IBR shall Ride-through unless the time duration at that voltage has exceeded the specified minimum Ride-through time duration. If the voltage is continuously varying over time, it is necessary to add the duration within each band of Tables 1 and 2 over any 10 second time period.
8. The specified duration of the mandatory operation regions and the permissive operation regions in Tables 1 and 2 is cumulative over one or more disturbances within any 10 second time period.
9. The IBR may trip for more than four deviations of the applicable voltage at the high-side of the main power transformer outside of the continuous operation region within any 10 second time period.
10. Instantaneous trip settings based on instantaneously calculated voltage measurements with less than filtering lengths of one cycle (16.6 millisecond) are not permissible.
11. The "must Ride-through zone" is the combined area of the mandatory operating regions, the continuous operating regions, and the permissive operating region. All area outside of these operating regions is referred to as the "may Ride-through zone".

Attachment 2: Frequency Ride-Through Criteria

Table 3: Frequency Ride-through Capability Requirements

System Frequency (Hz)	Minimum Ride-Through Time (sec)
> 64.0	May trip
≥ 61.8	6
≥ 61.5	299
> 61.2	660
≤ 61.2 and > 58.8	Continuous
≤ 58.8	660
≤ 58.5	299
≤ 57.0	6
< 56.0	May trip

1. Frequency measurements are taken at the high-side of the main power transformer.
2. Frequency is measured over a period of time (typically 3-6 cycles) to calculate system frequency at the high-side of the main power transformer.
3. Instantaneous or single points of measurement may not be used in the determination of control settings.
4. At any given frequency value, each IBR shall Ride-through unless the time duration at that frequency has exceeded the specified minimum ride-through time duration.
5. The specified durations of Table 3 are cumulative over one or more disturbances within a 15-minute time period.

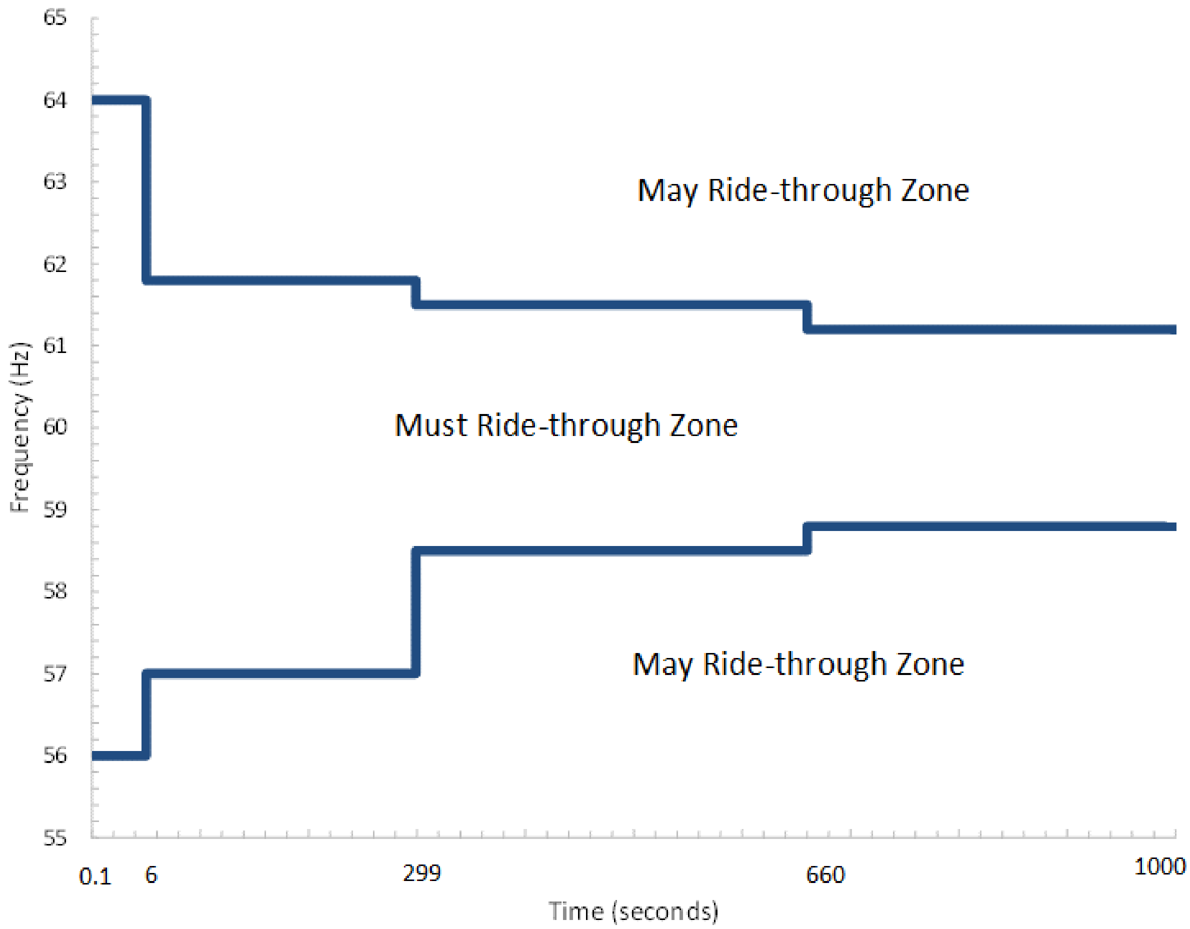

Figure 1: PRC-029 Frequency Ride-through Requirements

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

Draft 3 of PRC-029-1 is posted for a formal comment and additional ballot.

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023
25-day formal comment period and initial ballot	March 27 – April 22, 2024
15-day formal comment period and additional ballot	June 18 – July 8, 2024

Anticipated Actions	Date
15-day formal comment period and additional ballot	July 22 – August 12, 2024
Final Ballot	August 26 – September 6, 2024
Board adoption	October 8, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Ride-through: The entire plant/facility ~~R~~remaining connected~~, synchronized with~~ to the ~~Transmission~~ Bulk Power System~~,~~ and continuing in its entirety to operate ~~in response to System conditions~~ through ~~the time-frame of a~~ System Disturbances.

The term Inverter-based Resource (IBR) refers to proposed definitions being developed under the Project 2020-06 Verifications of Models and Data for Generators. As of this posting, the proposed definition of an IBR is:

IBR: A plant/facility consisting of individual devices that are capable of exporting Real Power through a power electronic interface(s) such as inverter or converter, and that are operated together as a single resource at a common point of interconnection to the electric system. IBRs include, but are not limited to, plants/facilities with solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell devices.

A. Introduction

1. **Title:** **Frequency and Voltage Ride-through Requirements for Inverter-Based Resources**
2. **Number:** **PRC-029-1**
3. **Purpose:** To ensure that ~~Inverter-Based Resources (~~IBR~~s) adhere to~~ Ride-through ~~requirements as expected~~ to support the Bulk Power System (BPS) during and after defined frequency and voltage excursions.
4. **Applicability:**
   - **4.1 Functional Entities:**
     - **4.1.1.** Generator Owner
     - ~~**4.1.2.** Transmission Owner[1]~~
   - **4.2 Facilities:**
     - **4.2.1.** The Elements associated with (1) Bulk Electric System (BES) IBRs ~~inverter-based resources[2]~~ and (2) Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.
     - ~~**4.2.2.** IBR Registration Criteria~~

Effective Date: See Implementation Plan for Project 2020-02 – PRC-029-1

Standard-Only Definition: None

~~[1] For owners of Voltage Source Converter – High-voltage Direct Current (VSC-HVDC) transmission facilities that are dedicated connections for IBR to the BPS~~

~~[2] For the purpose of this standard, "inverter-based resources" refers to a collection of individual solar photovoltaic (PV), Type 3 and Type 4 wind turbines, battery energy storage system (BESS), or fuel cells that operate as a single plant/resource. In case of offshore wind plants connecting via a dedicated VSC-HVDC, the inverter-based resource includes the VSC-HVDC system.~~

B. Requirements and Measures

R1. Each Generator Owner ~~or Transmission Owner~~ shall ensure the design and operation is such that each ~~facility~~ IBR meet or exceed ~~adheres to~~ Ride-through requirements, in accordance with the "must Ride-through[3] zone" as specified in Attachment 1, except for the following: *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

- The ~~facility~~ IBR needed to electrically disconnect in order to clear a fault; or
- The voltage at the high side of the main power transformer[4] went outside an accepted~~A documented equipment~~ hardware limitation, ~~exists~~ in accordance with Requirement R4; or
- The instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer and is initiated by a non-fault switching event on the transmission system[5]; or
- The Volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

M1. Each Generator Owner ~~and Transmission Owner~~shall have evidence ~~of dynamic simulations, studies, or other evidence~~ to demonstrate the design of each facility will adhere to Ride-through requirements, as specified in Requirement R1. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner ~~and Transmission Owner~~ shall ~~have~~ retain evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) to demonstrate that the operation of each ~~facility~~ IBR did adhere to Ride-through requirements, as specified in Requirement R1. If the Generator Owner ~~and Transmission Owner~~ choose to utilize Ride-through exemptions that occur within the "must Ride-through zone" and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner ~~and Transmission Owner~~ shall also ~~have~~ retain evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate that the ~~facility~~ IBR failed to Ride-through during a phase jump of greater than or equal to 25 electrical degrees, and documentation from their Transmission Planner, Reliability Coordinator, Planning Coordinator, or Transmission Operator that a non-fault initiated switching event occurred.

R2. Each Generator Owner ~~or Transmission Owner~~ shall ensure the design and operation is such that the voltage performance for each ~~facility~~ IBR adheres to the following during a voltage excursion, unless a documented ~~equipment~~ hardware limitation

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[3] Includes no tripping associated with phase lock loop loss of synchronism

[4] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for IBRs. In case of IBR connecting via a dedicated Voltage Source Converter High Voltage Direct Current (VSC-HVDC), the main power transformer is the main power transformer on the receiving end.

[5] Current blocking mode may be used for non-fault initiated phase jumps greater than 25 degrees in order to prevent tripping.

exists in accordance with Requirement R4. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

2.1. While the voltage at the high-side of the main power transformer~~[6]~~ remains within the continuous operation region as specified in Attachment 1, each ~~facility~~ IBR shall:

2.1.1 Continue to deliver the pre-disturbance level of ~~active~~ Real ~~p~~Power or available ~~active~~ Real ~~p~~Power[7], whichever is less.[8]

2.1.2 Continue to deliver R~~r~~eactive ~~p~~Power up to its ~~r~~Reactive ~~p~~Power limit and according to its controller settings.

2.1.3 Prioritize Real Power or Reactive Power ~~If the facility cannot deliver both active and reactive power due to a current limit or reactive power limit,~~ when the voltage is less than~~below~~ 0.95 per unit, the voltage is ~~and still~~ within the continuous operation region, and the IBR cannot deliver both Real Power and Reactive Power due to a current limit, unless otherwise specified through other mechanisms by an associated~~then preference shall be given to active or reactive power according to requirements if required by the~~ Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.2. While voltage at the high-side of the main power transformer is within the mandatory operation region as specified in Attachment 1, each IBR shall exchange current, up to the maximum capability to provide voltage support, on the affected phases during both symmetrical and asymmetrical voltage disturbances, either under[9]:

- Reactive P~~p~~ower priority by default; or
- ~~Active~~ Real ~~p~~Power priority if required through other mechanisms by an~~the~~ associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.3. While voltage at the high-side of the main power transformer is within the permissive operation region, as specified in Attachment 1, each ~~facility~~ IBR may operate in current block mode if necessary to avoid tripping. Otherwise, each

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~~[6] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for inverter-based resources. In case of offshore wind plants connecting via a dedicated VSC-HVDC, the main power transformer is the onshore main power transformer.~~

7 “Available Real Power" refers to changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes of facility Real Power attributed to IBR tripping in whole or part.

[8] Except if this would occur during a frequency excursion. The ~~active~~ Real ~~p~~Power response should recover in accordance with the primary frequency controller.

[9] In either case and if required, the magnitude of ~~active~~ Real ~~p~~Power and reactive current shall be as specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

~~facility~~ IBR shall follow the requirements for the mandatory operation region in Requirement R2.2.

2.3.1 If a ~~facility~~ IBR enters current block mode, it shall restart current exchange in less than or equal to five cycles of positive sequence voltage returning to a continuous operation region or mandatory operation region.

2.4. Each ~~facility~~ IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable high voltage thresholds and time durations in its response as voltage recovers from the mandatory or permissive operation regions to the continuous operation region.

2.5. Each ~~facility~~ IBR shall restore ~~active~~Real ~~p~~Power output to the pre-disturbance or available level[10] (whichever is lesser) within 1.0 second when the voltage at the high-side of the main power transformer returns from the mandatory operation region or permissive operation region (including operating in current block mode) to the continuous operation region, as specified in Attachment 1, unless ~~the~~ an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires a lower post-disturbance ~~active~~ Real ~~p~~Power level requirement or requires a different post-disturbance ~~active~~ Real ~~p~~Power restoration time through other mechanisms.[11]

M2. Each Generator Owner ~~and Transmission Owner~~ shall have evidence ~~of dynamic simulations, studies, or other evidence~~ to demonstrate the design of each ~~facility~~ IBR will adhere to requirements, as specified in Requirement R2. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner ~~and Transmission Owner~~ shall also retain~~have~~ evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate~~ing~~ that the operation of each ~~facility~~ IBR did adhere to performance requirements, as specified in Requirement R2, during each voltage excursion measured at the high-side of the main power transformer. The Generator Owner ~~or Transmission Owner~~ shall retain~~have~~ evidence of receiving such performance requirements, (e.g. email exchange, contract information) if the Transmission Planner, Transmission Operator, Reliability Coordinator, or Planning Coordinator has required the Generator Owner through other mechanisms~~or Transmission Owner~~ to follow performance requirements other than those in Requirement R2 (e.g. ramp rates, reactive power prioritization).

R3. Each Generator Owner ~~or Transmission Owner~~ shall ensure the design and operation is such that each ~~facility~~ IBR meets or exceeds~~adheres to~~ Ride-through requirements during a frequency excursion event whereby the System frequency remains within the "must Ride-through zone" according to Attachment 2 and the absolute rate of change

[10] "Available Real Power" refers to changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes of facility Real Power attributed to IBR tripping in whole or part.

[11] Except if this would occur during a frequency excursion. The active power response should recover in accordance with the primary frequency controller.

of frequency (RoCoF)[12] ~~–~~magnitude is less than or equal to 5 Hz/second. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

M3. Each Generator Owner ~~and Transmission Owner~~ shall have evidence ~~of dynamic simulations, studies, or other evidence~~ to demonstrate the design of each ~~facility~~ IBR will adhere to Ride-through requirements, as specified in Requirement R3. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner ~~and Transmission Owner~~ shall also ~~have~~ retain evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data ~~-~~to demonstrate the operation of each ~~facility~~ IBR did adhere to Ride-through requirements, as specified in Requirement R3, during each frequency excursion event measured at the high-side of the main power transformer.

R4. Each Generator Owner ~~and Transmission Owner~~ identifying an ~~facility~~ IBR that is in-service by the effective date of PRC-029-1, has known hardware limitations that prevent the ~~facility~~ IBR from meeting voltage Ride-through criteria as detailed in Requirements R1 and R2, and requires an exemption from specific voltage Ride-through criteria shall:[13] *Lower] [Time Horizon: Long-term Planning]*

4.1. Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1. This documentation shall include:

4.1.1 Identifying information of the IBR (name, facility #~~, other~~);

4.1.2 Which aspects of voltage ride-through requirements that the IBR would be unable to meet and the capability of the ~~equipment~~ hardware due to the limitation;

4.1.3 Identify the specific piece(s) of ~~equipment~~ hardware causing the limitation;

4.1.4 Supporting technical documentation verifying the limitation is due to hardware that needs to be physically replaced or that the limitation cannot be removed by software updates or setting changes, and;

4.1.5 Information regarding any plans to remedy the ~~equipment~~ hardware limitation (such as an estimated date).

4.2. Provide a copy of the information detailed in Requirement R4.1 to the ~~applicable~~ associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and ~~to~~ the ~~Regional Entity~~CEA no later than 12 months following the effective date of PRC-029-1.

4.2.1 Any response to additional information requested by the ~~applicable~~ associated Planning Coordinator(s), Transmission Planner(s),

[12] Rate of change of frequency (RoOCOoF) is calculated as the average rate of change for multiple calculated system frequencies for a time period of greater than or equal to 0.1 second. ROoCOoF is not calculated during the fault occurrence and clearance.

[13] The exemption requests for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

Transmission Operator(s), Reliability Coordinator(s), and ~~to~~ the ~~Regional Entity~~CEA shall be provided back to the requestor within 90 days of the request.

~~4.2.1~~4.2.2 Provide a copy of the acceptance of an hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s).[14]

4.3. Each Generator Owner ~~and Transmission Owner~~ with a previously ~~submitted~~ accepted limitation~~request for exemption~~ that replace the ~~equipment~~hardware causing the limitation shall document and communicate such an hardware ~~equipment~~ change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the hardware ~~equipment~~ change.

4.3.1 When existing ~~equipment~~ hardware causing the limitation is replaced, the exemption for that Ride-through criteria no longer applies.

M4. Each Generator Owner ~~and Transmission Owner seeking~~ submitting for an exemption for an IBR~~facilities~~ that ~~are~~ is in-service by the effective date of PRC-029-1, shall have evidence of submission to the ~~Regional Entity~~CEA consistent with the information listed in Requirement R4.1. Each Generator Owner ~~and Transmission Owner~~ shall have evidence of communicated copies of each submission in accordance with Requirement R4.2 and to the ~~applicable~~ associated entities described in Requirement R4.2. Acceptable types of evidence for submittals include but are not limited to, meeting minutes, agreements, copies of procedures or protocols in effect, or email correspondence. Acceptable types of evidence for a~~n~~ ~~equipment~~hardware limitation may include but is not limited to, documentation that contains study results, experience from an actual event, or manufacturer's advice. Each Generator Owner ~~and Transmission Owner~~ that receives a request for additional information under Requirement R4.2.1 shall have evidence of providing that information within 90 calendar days. Each Generator Owner that replaces -hardware ~~equipment~~ at an IBR ~~facility~~ that is directly associated with an ~~approved~~ accepted exemption and that hardware ~~equipment~~ is the cause for the limitation, shall have evidence of communicating the hardware ~~equipment~~ change to the ~~applicable~~ associated entities described in Requirement R4.3 within ~~3~~90 calendar days of the hardware ~~equipment~~ replacement.

[14] Acceptance by the CEA is verification that the information provided includes all information listed in Requirement R4.1.

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.

1.2. Evidence Retention: 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.

- Each Generator Owner ~~and Transmission Owner~~ shall retain evidence with Requirements R1, R2, and R3 in this standard for 36 calendar months or the date of the last audit, whichever is greater.
- Each Generator Owner ~~and Transmission Owner~~ shall retain evidence with Requirement R4 in this standard for five calendar years or the date of the last audit, whichever is greater.

1.3. Compliance Monitoring and Enforcement 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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Owner ~~or Transmission Owner~~ failed to demonstrate the design capability of each applicable ~~facility~~ IBR to Ride-through in accordance with Attachment 1, except for those conditions identified in Requirement R1.	N/A	N/A	The Generator Owner ~~or Transmission Owner~~ failed to demonstrate each applicable ~~facility~~ IBR adhered to Ride-through requirements in accordance with Attachment 1, except for those conditions identified in Requirement R1.
R2.	The Generator Owner ~~or Transmission Owner~~ failed to demonstrate the design capability of each applicable ~~facility~~ IBR to adhere to performance requirements during voltage excursions, as specified in Requirement R2.	N/A	N/A	The Generator Owner ~~or Transmission Owner~~ failed to demonstrate each applicable ~~facility~~ IBR adhered to performance requirements during voltage excursions, as specified in Requirement R2.
R3.	The Generator Owner ~~or Transmission Owner~~ failed to demonstrate the design capability of each applicable facility to Ride-through in accordance with Attachment 2.	N/A	N/A	The Generator Owner ~~or Transmission Owner~~ failed to demonstrate each applicable facility adhered to Ride-through requirements in accordance with Attachment 2.
R4.	The Generator Owner ~~or Transmission Owner~~ with a previously communicated	The Generator Owner ~~or Transmission Owner~~ with a previously communicated	The Generator Owner ~~or Transmission Owner~~ with a previously communicated	The Generator Owner ~~or Transmission Owner~~ failed to document complete

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~equipment~~ hardware limitation that ~~repairs or~~ replace~~s~~ the documented limiting hardware ~~equipment~~ but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and ~~Regional Entity~~CEA more than ~~3~~90 calendar days but less than or equal to ~~6~~120 calendar days after the change to the hardware~~equipment~~. OR The Generator Owner ~~or Transmission Owner~~ provided a copy to the applicable entities as detailed in Requirement R4.2 more than 12 months but less than or equal to 15 months after the effective date of Requirement R4. OR	hardware ~~equipment~~ limitation that ~~repairs or~~ replace~~s~~ the documented limiting hardware ~~equipment~~ but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and ~~Regional Entity~~CEA more than ~~6~~120 calendar days but less than or equal to ~~9~~150 calendar days after the change to the hardware~~equipment~~. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 120 days but less than or equal to 150 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.	hardware ~~equipment~~ limitation that ~~repairs or~~ replace~~s~~ the documented limiting hardware ~~equipment~~ but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and ~~Regional Entity~~CEA more than ~~9~~150 calendar days but less than or equal to 1~~2~~80 calendar days after the change to the hardware~~equipment~~. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 150 days but less than or equal to 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.	information for ~~facilities~~ IBR identified with known hardware limitations that prevent the ~~facility~~ IBR from meeting voltage Ride-through criteria as detailed in Requirements R1 or R2. OR The Generator Owner or Transmission Owner with a previously communicated hardware ~~equipment~~ limitation that ~~repairs or~~ replace~~s~~ the documented limiting hardware ~~equipment~~ but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s),Reliability Coordinator(s), and ~~Regional Entity~~ CEA more than 1~~2~~80 calendar days after the change to the hardware~~equipment~~.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 90 days but less than or equal to 120 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.			OR The Generator Owner or Transmission Owner failed to provide a copy to the applicable entities as detailed in R4.2 within 24 months after the effective date of R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan .

Version History

Version	Date	Action	Change Tracking
Initial Draft	3/27/24	Draft	
Draft 2	6/4/24	Revised following initial comment review	
Draft 3	7/22/24	Revised following additional comment review	

Attachment 1: Voltage Ride-Through Criteria

Table 1: Voltage Ride-Through Requirements for AC-Connected Wind ~~Facility~~IBR [15]

Voltage (per unit)[16]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[17]	N/A
~~≤ 1.20 and~~ ≥ 1.10	Mandatory Operation Region	1.0
~~≤ 1.10 and~~ > 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90 ~~and ≥ 0.70~~	Mandatory Operation Region	3.00
< 0.70 ~~and ≥ 0.50~~	Mandatory Operation Region	2.50
< 0.50 ~~and ≥ 0.25~~	Mandatory Operation Region	1.20
< 0.25 ~~and ≥ 0.10~~	Mandatory Operation Region	0.16
< 0.10	Permissive Operation Region	0.16

Table 22~~2~~: Voltage Ride-Through Requirements for All Other ~~Inverter-based Resource Facilities~~IBR

Voltage (per unit)[18]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[19]	N/A
~~≤ 1.20 and~~ > 1.10	Mandatory Operation Region	1.0
~~≤ 1.10 and~~ > 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90 ~~and ≥ 0.70~~	Mandatory Operation Region	6.00
< 0.70 ~~and ≥ 0.50~~	Mandatory Operation Region	3.00
< 0.50 ~~and ≥ 0.25~~	Mandatory Operation Region	1.20
< 0.25 ~~and ≥ 0.10~~	Mandatory Operation Region	0.32
< 0.10	Permissive Operation Region	0.32

[15] Type 3 and type 4 wind resources directly connected to the AC Transmission System.
[16] Refer to bullet #4~~5~~ below.
[17] These conditions are referred to as the "may Ride-through zone".
[18] Refer to bullet #4~~5~~ below.
[19] These conditions are referred to as the "may Ride-through zone".

1. Table 1 applies to type 3 and type 4 wind ~~facilities~~ IBR or hybrid IBR that include wind, unless connected via a dedicated VSC-HVDC transmission facility.
2. Table 2 applies to all other ~~inverter-based resource~~IBR ~~facility~~ types not covered in Table 1; including, but not limited to, the following facilities:
   a. ~~Inverter-based resources~~IBR, regardless of their energy resource, interconnecting via a dedicated VSC-HVDC transmission facility.
   b. Other ~~inverter-based resource~~IBR ~~plants~~ or hybrid ~~plants~~ IBR consisting of photovoltaic (PV) and BESS.
3. The applicable voltage for ~~Voltage Source Converter High Voltage Direct Current (~~VSC-HVDC~~)~~ system with a dedicated connection to an ~~inverter-based resource~~IBR is on the AC side of the transformer(s) that is (are) used to connect the VSC-HVDC system to the interconnected transmission system.
4. ~~Table 1 applies to hybrid facilities consisting of wind (type 3 or type 4) and various other IBR technologies. Otherwise, Table 2 applies to hybrid facilities with no wind (type 3 or type 4).~~

~~5.~~4. The voltage base for per unit calculation is the nominal phase-to-ground or phase-to-phase transmission system voltage unless otherwise defined by the Planning Coordinator, ~~or~~ Transmission Planner, or Transmission Owner.

~~6.~~5. The applicable voltage for Tables 1 and 2 is identified as the voltage max/min of phase-to-neutral or phase-to-phase fundamental root mean square (RMS) voltage at the high-side of the main power transformer.

~~7.~~6. Tables 1 and 2 are only applicable when the frequency is within the “must Ride-through zone” as specified in ~~Table 3~~ Figure 1 of Attachment 2.

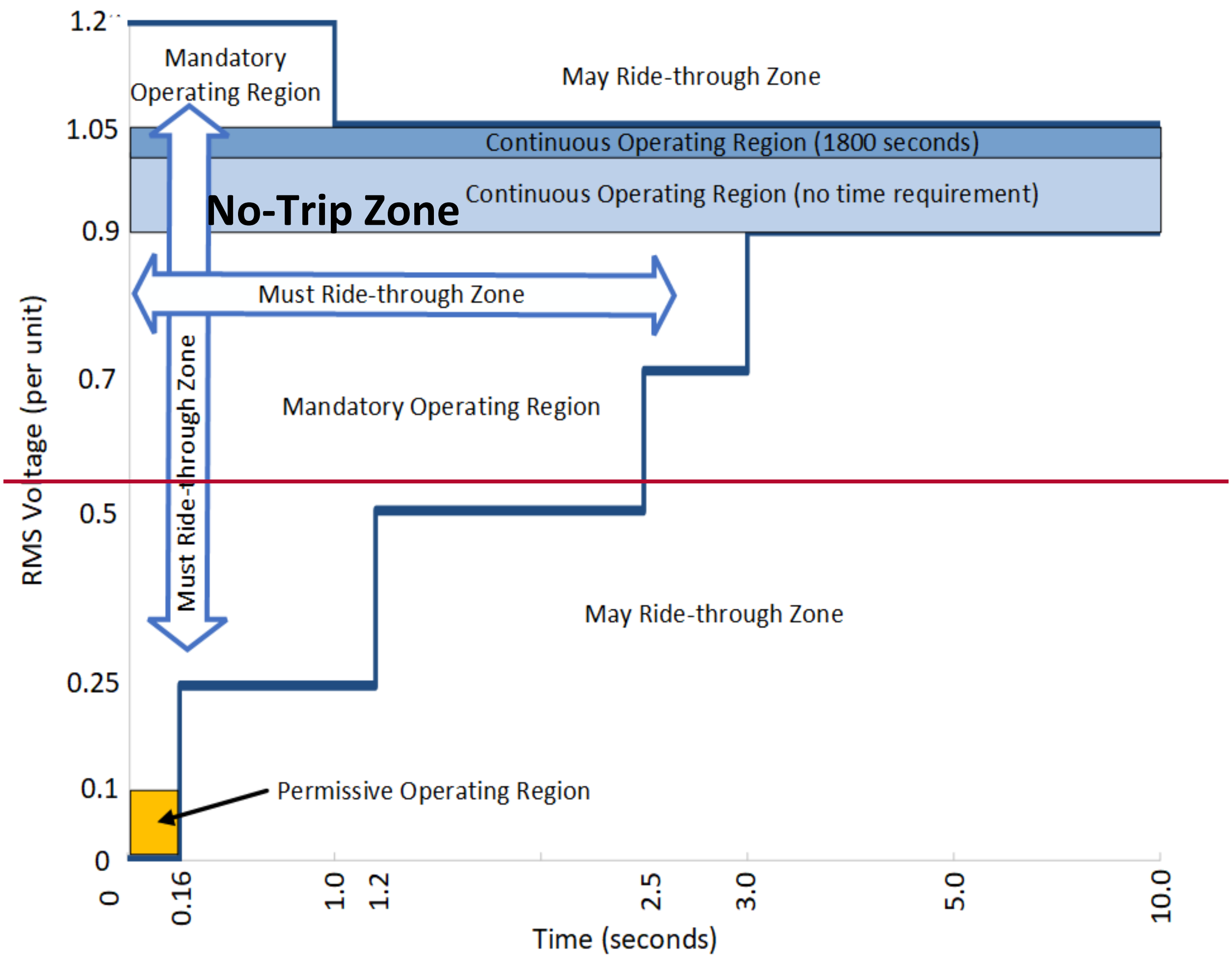
~~8.~~7. At any given voltage value, each ~~facility~~ IBR shall Ride-through unless the time duration at that voltage has exceeded the specified minimum Ride-through time duration. If the voltage is continuously varying over time, it is necessary to add the duration within each band of Tables 1 and 2 over any 10 second time period.

~~9.~~8. The specified duration of the mandatory operation regions and the permissive operation regions in Tables 1 and 2 is cumulative over one or more disturbances within any 10 second time period.

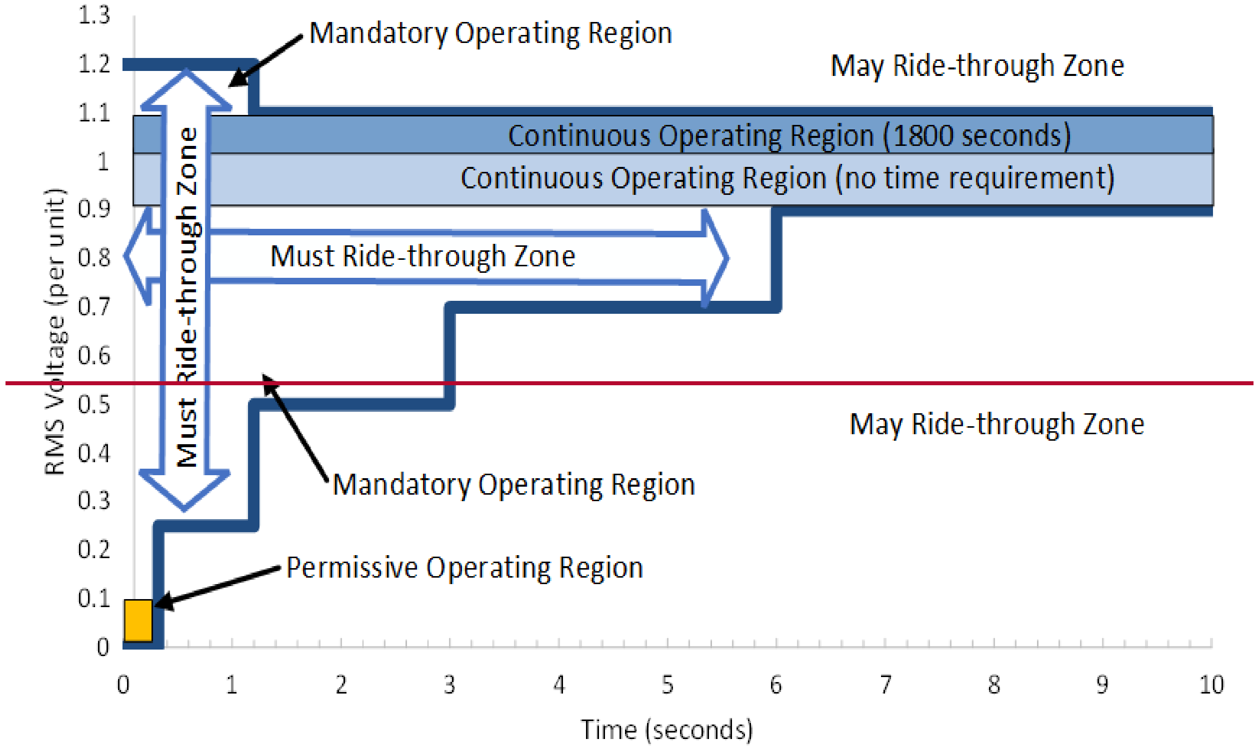
~~10.~~9. The ~~facility~~ IBR may trip for more than four deviations of the applicable voltage at the high-side of the main power transformer outside of the continuous operation region within any 10 second time period.

~~11.~~10. Instantaneous trip settings based on instantaneously calculated voltage measurements with less than filtering lengths of one cycle (16.6 msec) are not permissible.

~~12.~~11. The “must Ride-through zone” is the combined area of the mandatory operating regions, the continuous operating regions, and the permissive operating region. All area outside of these operating regions is referred to as the “may Ride-through zone”.



~~Figure 1: Voltage Ride-Through Requirements for AC-Connected Wind Facilities~~



~~Figure 2: Voltage Ride-Through Requirements for All Other IBR~~

Attachment 2: Frequency Ride-Through Criteria

Table 3: Frequency Ride-Through Capability Requirements

System Frequency (Hz)	Minimum Ride-Through Time (sec)
>~~≥~~ 64.0	May trip
~~< 64 and~~ ≥ 61.8	6
~~< 61.8 and~~ ≥ 61.5	299
~~< 61.5 and~~ > 61.2	660
≤ 61.2 and >~~<~~ 58.8	Continuous
≤ 58.8 ~~and < 58.8~~	660
≤~~<~~ 58.5 ~~and ≥ 57~~	299
≤~~<~~ 57.0 ~~and ≥ 56~~	6
< 56.0	May trip

1. Frequency measurements are taken at the high-side of the main power transformer.
2. Frequency is measured over a period of time (typically 3-6 cycles) to calculate system frequency at the high-side of the main power transformer.
3. Instantaneous or single points of measurement may not be used in the determination of control settings.
4. At any given frequency value, each facility shall Ride-through unless the time duration at that frequency has exceeded the specified minimum ride-through time duration.
5. The specified durations of Table 3 are cumulative over one or more disturbances within a 15-minute time period.

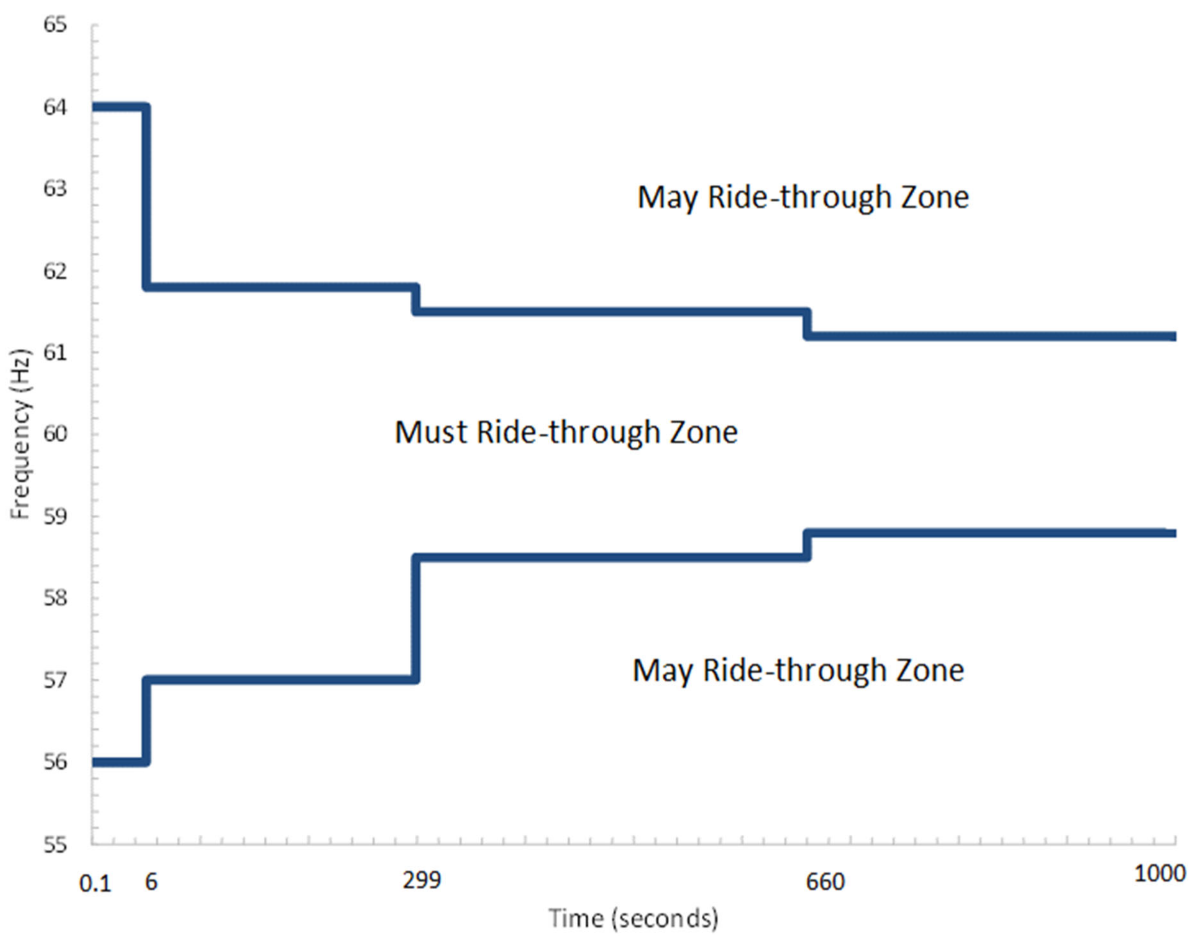


Figure ~~3~~1: PRC-029 Frequency Ride-Through Requirements

Implementation Plan

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
Reliability Standards PRC-024-4 and PRC-029-1

Applicable Standard(s)

- PRC-024-4 – Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and Type 2 Wind Resources, and Synchronous Condensers
- PRC-029-1 – Frequency and Voltage Ride-through Requirements for Inverter-based Generating Resources

Requested Retirement(s)

- PRC-024-3 Frequency and Voltage Protection Settings for Generating Resources

Prerequisite Standard(s)

- None

Proposed Definition(s)

- None

Applicable Entities

- See subject Reliability Standards.

Background

The purpose of Project 2020-02 is to modify Reliability Standard PRC-024-3 or replace it with a performance-based Ride-through standard that ensures generators remain connected to the Bulk Power System (BPS) during system disturbances. Specifically, the project focuses on using disturbance monitoring data to substantiate inverter-based resource (IBR) ride-through performance during grid disturbances. The project also ensures associated generators that fail to Ride-through system events are addressed with a corrective action plan (if possible) and reported to necessary entities for situational awareness.

The purpose for this project is based on the culmination of multiple analyses conducted by the ERO Enterprise regarding widespread IBR tripping events. Furthermore, the NERC Inverter-Based Resource Performance Subcommittee[1] has developed comprehensive recommendations for improved

[1] See documents at the NERC IRPS website: https://www.nerc.com/comm/RSTC/Pages/IRPS.aspx and the previous Inverter-Based Resource Performance Working Group website https://www.nerc.com/comm/RSTC/Pages/IRPWG.aspx

performance of IBRs, including the recommendation to develop comprehensive ride-through requirements.

In October 2023, FERC issued Order No. 901[2] which directs the development of new or modified Reliability Standards that include new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. In January 2024, NERC submitted a filing to FERC outlining a comprehensive work plan to address the directives within Order No. 901.[3] Within the work plan, NERC identified three active Standards Development projects that would need to be filed for regulatory approval with FERC by November 4, 2024. These projects include **2020-02 Modifications to PRC-024 (Generator Ride-through)**[4], **2021-04 Modifications to PRC-002-2**[5], and **2023-02 Analysis and Mitigation of BES Inverter-based Resource Performance Issues**[6].

Project 2020-02
Proposed Reliability Standard PRC-029-1 is a new Reliability Standard that includes Ride-through requirements and performance requirements for IBRs. The scope of this project was adjusted to align with associated regulatory directives from FERC Order No. 901 and the scope of the other projects related to “Milestone 2” of the NERC work plan. The components of this project’s Standard Authorization Request (SAR) that related to the inclusions of new data recording requirements are covered in Project 2021-04 and the proposed new PRC-028-1 Reliability Standard. Components of this project’s SAR that relate to analytics and corrective actions plans are covered in Project 2023-02 and the proposed new PRC-030-1 Reliability Standard.

PRC-029-1 includes requirements for Generator Owner IBR to continue to inject current and perform voltage support during a BPS disturbance. The standard also specifically requires Generator Owner IBR to prohibit momentary cessation in the no-trip zone during disturbances.

PRC-024-4 includes modifications to revise applicable facility types to remove IBR, retain type 1 and type 2 wind, and to include synchronous condensers.

[2] See FERC Order 901, Docket No. RM22-12-000; https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false; October 19, 2023
[3] See INFORMATIONAL FILING OF THE NORTH AMERICAN RELIABILITY CORPORATION REGARDING THE DEVELOPMENT OF RELIABILITY STANDARDS RESPONSIVE TO ORDER NO. 901 https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/NERC%20Compliance%20Filing%20Order%20No%20901%20Work%20Plan_packaged%20-%20public%20label.pdf; January 17, 2024
[4] See NERC Standards Development Project page for Project 2002-02; https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx
[5] See NERC Standards Development Project page for Project 2021-04; https://www.nerc.com/pa/Stand/Pages/Project-2021-04-Modifications-to-PRC-002-2.aspx
[6] See NERC Standards Development Project page for Project 2023-02; https://www.nerc.com/pa/Stand/Pages/Project-2023-02-Performance-of-IBRs.aspx

General Considerations

This implementation plan recognizes the urgent need for Reliability Standards to address IBR ride through performance, as demonstrated by multiple event reports of the last decade, while providing a reasonable period of time for entities to develop the necessary procedures and change their protection and control settings to meet the new requirements. The ERO Enterprise acknowledges that there are IBRs currently in operation and unable to meet voltage Ride-through requirements due to their inability to modify their coordinated protection and control settings. Consistent with FERC Order No. 901, a limited and documented exemption process for those IBR is appropriate and included within this Implementation Plan. Other NERC Standards Development projects will be pursued to address ongoing identification and mitigation of any potential reliability impacts to the BPS for such exemptions.

This implementation plan also recognizes that certain requirements (Requirements R1, R2, and R3) call for entities to "ensure the design and operation" of their IBR units meets certain criteria. Design elements may be implemented more expeditiously than operation requirements; the latter of which will require entities to show compliance through use of actual disturbance monitoring data. Therefore, this implementation plan provides staggered timeframes by which entities shall first ensure the design of their IBR units meets the criteria (12 months following regulatory approval). Subsequent compliance with the "operation" elements of these requirements shall become due as entities install disturbance monitoring equipment on each applicable IBR in accordance with the implementation plan for proposed Reliability Standard PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-based Resources.

The ERO Enterprise acknowledges that Generator Owners and Generator Operators owning or operating Bulk Power System connected IBRs that do not meet NERC's current definition of Bulk Electric System ("BES") will be registered no later than May 2026 in accordance with the IBR Registration proceeding in FERC Docket No. RR24-2. To ensure an orderly registration and compliance process for these entities, as well as fairness and consistency in the standard's application among similar asset types, this implementation plan provides additional time for both new and existing registered entities to come into compliance with Reliability Standard PRC-029-1's requirements for their applicable IBRs not meeting the BES definition. In so doing, this implementation plan advances an orderly process for new registrants while allowing existing entities to focus their immediate efforts on their assets posing the highest risk to the reliable operation of the Bulk Power System.

Effective Date and Phased-in Compliance Dates

The effective dates for the proposed Reliability Standards are provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance dates for those particular sections represent the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

PRC-024-4
Where approval by an applicable governmental authority is required, Reliability Standard PRC-024-4 shall become effective on the first day of the first calendar quarter that is twelve months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the Reliability Standard PRC-024-4 shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

PRC-029-1
Where approval by an applicable governmental authority is required, Reliability Standard PRC-029-1 shall become effective on the first day of the first calendar quarter that is twelve months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the Reliability Standard PRC-029-1 shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

PRC-029-1 Phased-in Compliance Dates

Requirements R1, R2, and R3

Capability-Based Elements

Bulk Electric System IBRs
Entities shall comply with the portion of Requirements R1, R2, and R3 relating to the **design** of their BES IBRs to meet the requirements by the effective date of the standard.

Applicable Non-BES IBRs[7]
Entities shall not be required to comply with Requirements R1, R2, and R3 relating to the **design** of their applicable non-BES IBRs until the later of: (1) January 1, 2027; or (2) the effective date of the standard.

Performance-Based Elements (all applicable IBRs)
Entities shall not be required to comply with the portion of Requirements R1, R2, and R3 relating to the **operation** of IBRs to meet the requirements until the entity has established the required

[7] The standard defines such as IBRs as "Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV."

disturbance monitoring equipment capabilities for those IBRs in accordance with the implementation plan for Reliability Standard PRC-028-1.

Requirement R4

Bulk Electric System IBRs
Entities shall comply with Requirement R4 for their BES IBRs by the effective date of the standard.

Applicable Non-BES IBRs
Entities shall not be required to comply with Requirement R4 or their non-BES IBRs until the later of: (1) January 1, 2027; or (2) the effective date of the standard.

Retirement Date

PRC-024-3

Reliability Standard PRC-024-3 shall be retired immediately prior to the effective date of Reliability Standards PRC-024-4 and PRC-029-1 in the particular jurisdiction in which the revised standard is becoming effective.

Equipment Limitations and Process for Requirement R4

Consistent with FERC Order No. 901, a limited and documented exemption for some legacy IBR with certain documented equipment limitations are acceptable. Per the Order, these IBRs are

> "…typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements."[8]

To ensure compliance with Requirement R4 and alignment with FERC Order No. 901, only those IBR that are in operation as of the effective date of PRC-029-1 may be considered for potential exemption. Further, only those IBR that are unable to meet voltage ride-through requirements due to their inability to modify their coordinated protection and control settings may be considered for potential exemption.

[8] Order No. 901 at p. 193.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
Reliability Standards PRC-024-4 and PRC-029-1

Applicable Standard(s)

- PRC-024-4 Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and Type 2 Wind Resources, and Synchronous Condensers
- PRC-029-1 Frequency and Voltage Ride-~~-T~~through Requirements for Inverter-Based Generating Resources

Requested Retirement(s)

- PRC-024-3 Frequency and Voltage Protection Settings for Generating Resources

Prerequisite Standard(s)

- ~~PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources~~None

Proposed Definition(s)

- None

Applicable Entities

- See subject Reliability Standards.

Background

The purpose of Project 2020-02 is to modify Reliability Standard PRC-024-3 or replace it with a performance-based R~~r~~ide-through standard that ensures generators remain connected to the Bulk-Power System (BPS) during system disturbances. Specifically, the project focuses on using disturbance monitoring data to substantiate inverter-based resource (IBR) ride-through performance during grid disturbances. The project also ensures associated generators that fail to ~~r~~Eide-through system events are addressed with a corrective action plan (if possible) and reported to necessary entities for situational awareness.

The purpose for this project is based on the culmination of multiple analyses conducted by the ERO Enterprise regarding widespread ~~inverter-based resource~~IBR tripping events. Furthermore, the NERC Inverter-Based Resource Performance Subcommittee[1] has developed comprehensive recommendations

[1] See documents at the NERC IRPS website: https://www.nerc.com/comm/RSTC/Pages/IRPS.aspx and the previous Inverter-Based Resource Performance Working Group website https://www.nerc.com/comm/RSTC/Pages/IRPWG.aspx

for improved performance of inverter-based resources, including the recommendation to develop comprehensive ride-through requirements.

In October 2023, FERC issued Order No. 901[2] which directs the development of new or modified Reliability Standards that include new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. In January 2024, NERC submitted a filing to FERC outlining a comprehensive work plan to address the directives within Order No. 901.[3] Within the work plan, NERC identified three active Standards Development projects that would need to be filed for regulatory approval with FERC by November 4, 2024. These projects include **2020-02 Modifications to PRC-024 (Generator Ride-through)**[4], **2021-04 Modifications to PRC-002-2**[5], and **2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues**[6].

Project 2020-02

Proposed Reliability Standard PRC-029-1 is a new Reliability Standard that includes ~~r~~Ride-through requirements and performance requirements for IBRs. The scope of this project was adjusted to align with associated regulatory directives from FERC Order No. 901 and the scope of the other projects related to "Milestone 2" of the NERC work plan. The components of this project's Standard Authorization Request (SAR) that related to the inclusions of new data recording requirements are covered in Project 2021-04 and the proposed new PRC-028-1 Reliability Standard. Components of this project's SAR that relate to analytics and corrective actions plans are covered in Project 2023-02 and the proposed new PRC-030-1 Reliability Standard.

PRC-029-1 includes requirements for Generator Owner ~~and Transmission Owner~~ IBR to continue to inject current and perform ~~frequency~~ voltage support during a BPS disturbance. The standard also specifically requires Generator Owner ~~and Transmission Owner~~ IBR to prohibit momentary cessation in the no-trip zone during disturbances.

PRC-024-4 includes modifications to revise applicable facility types to remove IBR, retain type 1 and type 2 wind, and to include synchronous condensers.

[2] See FERC Order 901, Docket No. RM22-12-000; https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false; October 19, 2023
[3] See INFORMATIONAL FILING OF THE NORTH AMERICAN RELIABILITY CORPORATION REGARDING THE DEVELOPMENT OF RELIABILITY STANDARDS RESPONSIVE TO ORDER NO. 901 https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/NERC%20Compliance%20Filing%20Order%20No%20901%20Work%20Plan_packaged%20-%20public%20label.pdf; January 17, 2024
[4] See NERC Standards Development Project page for Project 2002-02; https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx
[5] See NERC Standards Development Project page for Project 2021-04; https://www.nerc.com/pa/Stand/Pages/Project-2021-04-Modifications-to-PRC-002-2.aspx
[6] See NERC Standards Development Project page for Project 2023-02; https://www.nerc.com/pa/Stand/Pages/Project-2023-02-Performance-of-IBRs.aspx

General Considerations

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This implementation plan also recognizes that certain requirements (Requirements R1, R2, and R3) call for entities to "ensure the design and operation" of their IBR units meets certain criteria. Design elements may be implemented more expeditiously than operation requirements; the latter of which will require entities to show compliance through use of actual disturbance monitoring data. Therefore, this implementation plan provides staggered timeframes by which entities shall first ensure the design of their IBR units meets the criteria (12 months following regulatory approval). Subsequent compliance with the "operation" elements of these requirements shall become due as entities install disturbance monitoring equipment on each applicable IBR in accordance with the implementation plan for proposed Reliability Standard PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-based Resources.

The ERO Enterprise acknowledges that Generator Owners and Generator Operators owning or operating Bulk Power System connected IBRs that do not meet NERC's current definition of Bulk Electric System ("BES") will be registered no later than May 2026 in accordance with the IBR Registration proceeding in FERC Docket No. RR24-2. To ensure an orderly registration and compliance process for these entities, as well as fairness and consistency in the standard's application among similar asset types, this implementation plan provides additional time for both new and existing registered entities to come into compliance with Reliability Standard PRC-029-1's requirements for their applicable IBRs not meeting the BES definition. In so doing, this implementation plan advances an orderly process for new registrants while allowing existing entities to focus their immediate efforts on their assets posing the highest risk to the reliable operation of the Bulk Power System.

Effective Date and Phased-in Compliance Dates

The effective dates for the proposed Reliability Standards are provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance dates for those particular sections represent the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

PRC-024-4
Where approval by an applicable governmental authority is required, Reliability Standard PRC-024-4 shall become effective on the first day of the first calendar quarter that is ~~6~~twelve months after the effective date of the applicable governmental authority's order approving the ~~PRC-028-1~~ standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the Reliability Standard PRC-024-4 shall become effective on the first day of the first calendar quarter that is twelve~~6~~ months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

PRC-029-1
Where approval by an applicable governmental authority is required, Reliability Standard PRC-029-1 shall become effective on the first day of the first calendar quarter that is twelve ~~six~~ months after the effective date of the applicable governmental authority's order approving the ~~PRC-028-1~~ standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the Reliability Standard PRC-029-1 shall become effective on the first day of the first calendar quarter that is twelve ~~six~~ months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

PRC-029-1 Phased-in Compliance Dates

Requirements R1, R2, and R3

Capability-Based Elements

Bulk Electric System IBRs
Entities shall comply with the portion of Requirements R1, R2, and R3 relating to the **design** of their BES IBRs to meet the requirements by the effective date of the standard.

Applicable Non-BES IBRs[7]
Entities shall not be required to comply with Requirements R1, R2, and R3 relating to the **design** of their applicable non-BES IBRs until the later of: (1) January 1, 2027; or (2) the effective date of the standard.

Performance-Based Elements (all applicable IBRs)
Entities shall not be required to comply with the portion of Requirements R1, R2, and R3 relating to the **operation** of IBRs to meet the requirements until the entity has established the required

[7] The standard defines such as IBRs as "Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV."

disturbance monitoring equipment capabilities for those IBRs in accordance with the implementation plan for Reliability Standard PRC-028-1.

Requirement R4

Bulk Electric System IBRs
Entities shall comply with Requirement R4 for their BES IBRs by the effective date of the standard.

Applicable Non-BES IBRs
Entities shall not be required to comply with Requirement R4 or their non-BES IBRs until the later of: (1) January 1, 2027; or (2) the effective date of the standard.

Retirement Date

PRC-024-3

Reliability Standard PRC-024-3 shall be retired immediately prior to the effective date of Reliability Standards PRC-024-04 and PRC-029-1 in the particular jurisdiction in which the revised standard is becoming effective.

Equipment Limitations and Process for Requirement R4

Consistent with FERC Order No. 901, a limited and documented exemption for some legacy IBR with certain documented equipment limitations are acceptable. Per the Order, these IBRs are

> "…typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements."[8]

To ensure compliance with Requirement R4 and alignment with FERC Order No. 901, only those IBR that are in operation as of the effective date of PRC-029-1 may be considered for potential exemption. Further, only those IBR that are unable to meet voltage ride-through requirements due to their inability to modify their coordinated protection and control settings may be considered for potential exemption.

[8] Order No. 901 at p. 193.

Unofficial Comment Form

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2020-02 Modifications to PRC-024 (Generator Ride-through)** by **8 p.m. Eastern, Monday, August 12, 2024.**

Additional information is available on the project page. If you have questions, contact Manager of Standards Development, Jamie Calderon (email), or at 404-960-0568.

Background Information

The goal of Project 2020-02 is to mitigate the recent and ongoing disturbance ride through performance issues identified across multiple Interconnections and numbers of disturbances analyzed by NERC and the Regions. These issues have been associated with Inverter-Based Resources (IBR) with many causes of their tripping or cessation unrelated to voltage and frequency protection settings requirements in the currently effective version of PRC-024, PRC-024-3. Proposed Reliability Standard PRC-024-4 includes revisions to limits its applicability to synchronous generators and synchronous condensers only and remains as a protection-based standard. A new standard, PRC-029-1, is proposed as a true disturbance ride-through Reliability Standard with applicability to inverter-based resources.

In October 2023, FERC issued Order No. 901, which directed NERC to develop new or modified existing Reliability Standards that include new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. Project 2020-02 was one of three projects identified by NERC that must be completed and filed with FERC by November 4, 2024 to address Order No. 901 directives. At the December 2023 SC meeting, the SC approved waivers for Project 2020-02, allowing formal comment periods to be reduced from 45 days to 25 calendar days, and final ballot periods to be reduced from 10 days to as few as 5 calendar days.

The initial draft of the PRC-024-4 and PRC-029-1 drafts were posted for comment March 27- April 22, 2024. Comments were reviewed and incorporated. An additional draft was posted for comment June 28 – July 8, 2024. Substantive changes were made to the PRC-029-1 draft based on comments received. Formal comment responses are available in the consideration of comments received document posted along with these additional drafts. The additional draft for PRC-024-4 passed with an 82.7% successful ballot and is presented in this posting for Final Ballot.

Questions

1. Do you agree with the proposed definition of Ride-through? If not, please state what revision would be acceptable and why.

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with the changes made in this draft of PRC-029-1.

   ☐ Yes
   ☐ No

   Comments:

3. Provide any additional comments for the Drafting Team to consider, if desired.

   Comments:

Technical Rationale

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

PRC-029-1 – Frequency and Voltage Ride-through Requirements for Inverter-based Generating Resources

General Rationale

The drafting team has created a new Reliability Standard (PRC-029-1) to address inverter-based resource (IBR) disturbance Ride-through performance criteria. This proposal is a consequence of both the different natures of synchronous and inverter-based generation resources and several recent events exhibiting significant IBR Ride-through deficiencies. The proposed PRC-029-1 coincides with certain Ride-through requirements of IEEE 2800-2022 but is structured to follow language from FERC Order No. 901, which states that "NERC has the discretion to consider during its standards development process whether and how to reference IEEE standards in the new or modified Reliability Standards."[1]

The lack of standardization of IBR technology (equipment/controller behavior) has created reliability challenges associated with the interconnection of IBR facilities to the power grid. The nature of the fast switching of power electronics of IBR generation and the electronic interface to the transmission system is such that disturbance Ride-through behavior is largely determined by manufacturer-specific equipment and controls system designs. These controls may be programmed but also have more restrictive limits on current, both in magnitude and duration. IBR responses to grid disturbances are highly controlled and managed by using fast switching of power electronics devices dependent upon manufacturer specific control system design that can be programmed in many ways and with various and concurrent Ride-through performance objectives. Rather than attempting to restrict the myriad of control approaches, protections, and settings, it is more straightforward to require Ride-through during defined frequency and voltage excursions.

In contrast to synchronous generation, the need for IBR Ride-through requirements has been heightened by recent events during which IBRs have not met PRC-024-3 frequency and voltage Ride-through expectations, often due to controls and protection only indirectly associated with the system voltage and frequency excursions. In addition to Ride-through, there is the question of what IBRs should be doing as they Ride-through. IBR responses to system disturbances can be beneficial or detrimental to both their own Ride-through and system reliability, often depending on adjustable control settings. Thus, it is essential to set expectations on performance during Ride-through as well as Ride-through capability.

A further reason for proposing a separate IBR standard is that IBRs do not provide inertia or short circuit contributions, unlike synchronous machines. The drafting team thinks that IBRs should compensate for their lack of inertia and short circuit contributions with wider tolerances for frequency and voltage

[1] P 195, FERC Order No. 901; https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false; October 17, 2023

excursions. This is the reason for the differences in the frequency and voltage tables and graphs between the PRC-024-4 and PRC-029-1 standards.

The proposed PRC-029-1 must be understood generally as an event-based standard though it is also required to provide evidence of the ability to Ride-through disturbance events by means of dynamic models and simulation results. Compliance with PRC-029-1 is determined chiefly though not exclusively from IBR Ride-through performance during transmission system events in the field. An IBR becomes noncompliant with PRC-029-1 when an event in the field occurs that shows that one or more requirements were not satisfied. This intent is clarified by *Operations Assessment* as the Time Horizon designation of requirements R1-R3.

FERC Order No. 901 Directives

PRC-029-1 is proposed in consideration of directives from FERC Order No. 901 that were assigned to the Project 2020-02 drafting team. The following directives were assigned to this drafting team for inclusion in this standards project (paragraph numbers of the FERC Order are included for reference):

- Paragraph 190: "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults."
- Paragraph 190: "The new or modified Reliability Standards must require registered IBRs to continue to inject current and perform frequency support during a Bulk-Power System disturbance."
- Paragraph 190: "Any new or modified Reliability Standard must also require registered IBR generator owners and operators to prohibit momentary cessation in the must Ride-through zone during disturbances."
- Paragraph 190: "NERC must submit new or modified Reliability Standards that establish IBR performance requirements, including requirements addressing frequency and voltage ride through, post-disturbance ramp rates, phase lock loop synchronization, and other known causes of IBR tripping or momentary cessation."
- Paragraph 193: "Therefore, we direct NERC through its standard development process to determine whether the new or modified Reliability Standards should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements."
- Paragraph 193: "Further, we direct NERC to ensure that any such exemption would be applicable for only existing equipment that is unable to meet voltage Ride-through performance. When such existing equipment is replaced, the exemption would no longer apply, and the new equipment must comply with the appropriate IBR performance requirements specified in the Reliability Standards (e.g., voltage and frequency ride through, phase lock loop, ramp rates, etc.)."

- Paragraph 193: "Finally, we direct NERC, through its standard development process, to require the limited and documented exemption list (i.e., IBR generator owner and operator exemptions) to be communicated with their respective Bulk-Power System planners and operators (e.g., the IBR generator owner's or operator's planning coordinator, transmission planner, reliability coordinator, transmission operator, and balancing authority)."
- Paragraph 199: "Pursuant to section 215(d)(5) of the FPA, we modify the NOPR proposal. To the extent NERC determines that a limited and documented exemption for those registered IBRs currently in operation and unable to meet voltage Ride-through requirements is appropriate due to their inability to modify their coordinated protection and control settings, we direct NERC to develop new or modified Reliability Standards to mitigate the reliability impacts to the Bulk-Power System of such an exemption."
- Paragraph 208: "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop and submit to the Commission for approval new or modified Reliability Standards that require post-disturbance ramp rates for registered IBRs to be unrestricted and not programmed to artificially interfere with the resource returning to a pre-disturbance output level in a quick and stable manner after a Bulk-Power System."
- Paragraph 209: "The proposed new or modified Reliability Standards must require registered IBRs to ride through momentary loss of synchronism during Bulk-Power System disturbances and require registered IBRs to continue to inject current into the Bulk-Power System at pre-disturbance levels during a disturbance, consistent with the IBR Interconnection Requirements Guideline and Canyon 2 Fire Event Report recommendations."
- Paragraph 209: "Related to ACP/SEIA's comment recommending to revise the directive to require generators to maintain synchronism where possible and continue to inject current to support system stability, we direct NERC, through its standard development process, to consider whether there are conditions that may limit generators to maintain synchronism."
- Paragraph 209: "We direct NERC to submit to the Commission for approval new or modified Reliability Standards that would require registered IBRs to ride through any conditions not addressed by the proposed new or modified Reliability Standards that address frequency or voltage ride through, including phase lock loop loss of synchronism."
- Paragraph 226: "Further, we believe that there is a need to have all of the directed Reliability Standards effective and enforceable well in advance of 2030 and direct NERC to ensure that the associated implementation plans sequentially stagger the effective and enforceable dates to ensure an orderly industry transition for complying with the IBR directives in this final rule prior to that date." (*pertains multiple projects*)

Rationale for Applicability Section (4.0)

Functional Entities (4.1)

The functional entity responsible for assuring acceptable Ride-through performance of IBR is either the Generator Owner.

Facilities (4.2)

Applicability Facilities include only IBR that also meet NERC registration criteria. Language used within PRC-029-1 applicability only refers to IBR as a whole plant/facility. Consistent with FERC Order No. 901, IBR performance is based on the overall IBR plant and disturbance monitoring equipment requirements established under the proposed PRC-028-1. Requirements within PRC-029-1 do not apply to individual inverter units or measurements taken at individual inverter unit terminals.

Rationale for Requirement R1

The objective of Requirement R1 is to ensure that all applicable IBRs will Ride-through grid voltage disturbances consistent with the must Ride-through zone and operation regions specified in **Attachment 1**. IBRs must be able to demonstrate Ride-through performance, that they remain electrically connected, i.e., shall not trip, and continue to exchange current, i.e., shall not enter momentary cessation.

The drafting team determined that the definition of “must Ride-through zones” and “operation regions” should be consistent with those terms as used within IEEE 2800-2022. Additionally, the team determined that the voltage thresholds of each operation region should be based on measurements taken on the high-side of the main power transformer in PRC-029-1, also consistent with IEEE 2800-2022.

Battery Energy Storage Systems (BESS) units also must comply with Requirement R1 in all operating modes including charging, discharging, and idle (energized but not charging or discharging). A BESS in idle mode must be capable of responding to system voltage and frequency excursions as it does in charging or discharging modes.

Exceptions to **Attachment 1** performance criteria are allowable when 1) an IBR needs to trip to clear a fault, 2) voltage at the high-side of the main power transformer goes outside an accepted and a documented hardware equipment limitation established in accordance with Requirement R4, 3) instantaneous positive sequence voltage phase angle jumps more than 25 electrical degrees at the high-side of the main power transformer initiated by a non-fault switching events occur on the transmission system, or 4) volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

When a grid disturbance occurs, such as a close-in fault or a relatively large switching event, the grid voltage may experience a rapid phase angle shift. In such cases, the phase displacement $\Delta\theta$ can be large enough to pose challenges for the phase lock loop (PLL) to track the terminal voltage, cause control instability within the inverter, such as the inner current control loop or the DC link control loop, and even lead to tripping of the inverter due to the malfunction of the controls.

Since phase angle jumps are common occurrences on the BPS, this standard requires the IBR to be designed and operated to Ride-through a minimum phase angle jump of 25 electrical degrees. This is a typical value and aligns with the requirement in IEEE 2800-2022.

Some IBR equipment has PLL loss of synchronism protection, referring to a protective function that operates when the angle displacement $\Delta\theta$ exceeds a threshold for a predetermined period of time (on the order of a couple of milliseconds). Historically, this protection has been used by some inverter manufacturers, especially for inverters in distribution systems. For the IBR connected to the BPS, this protection function should be disabled. If it is enabled, the phase angle jump protection setting should be configured such that the IBR shall only trip to prevent equipment damage.

Rationale for Requirement R2

In addition to having minimum voltage Ride-through capability specified in Requirement R1, all applicable IBRs are also required to adhere to certain voltage Ride-through performance criteria during system disturbances. Acceptable performance criteria depend on the operation region that an IBR is presently in or when in transition from one operation region to another operation region. Requirement R2 includes specific performance criteria and is needed to assure consistent IBR performance within and each operation region in **Attachment 1** and when in transition between regions.

Rationale for Requirement R2.1

This subpart of Requirement R2 ensures that when the voltage at the high-side of the main power transformer (MPT) recovers to the continuous operation region from either the mandatory operation region or the permissive operation region, an IBR delivers the pre-disturbance level of Real Power or available Real Power, whichever is less. Available Real Power allows for changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes attributed to IBR tripping in whole or part. This requires an IBR to exit the “High Voltage Ride Through (HVRT)” or “Low Voltage Ridge Through (LVRT)” modes properly such that it does not cause reduction in the Real Power when the high-side of MPT voltage recovers to within the continuous operation region.

When the voltage at the high-side of the MPT is greater than 0.90 per-unit and less than 0.95 per-unit, IBRs are expected to exit the LVRT mode and come back to “normal operating mode”. If an IBR has a default total current limit of 1.0 per-unit, the apparent power production of an IBR will be limited below 1.0 per-unit (e.g., the per-unit value of IBR terminal voltage). In such case, the IBR needs to configure a preference setting, either to maintain pre-disturbance Real Power or maximize the Reactive Power in order to further help with voltage recovery, or according to requirements specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Rationale for Requirement R2.2

This subpart of Requirement R2 ensures that when the voltage at the high-side of the MPT is within the mandatory operation region, IBRs inject or absorb reactive current proportional to the level of terminal voltage deviations they measure. IBRs shall follow Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specified certain magnitude of Reactive Power response to voltage changes, if available.

By default, reactive current prioritization shall be configured unless Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires Real Power priority.

Rationale for Requirement R2.3

This subpart of Requirement R2 ensures that when the voltage at the high-side of the MPT is within the permissive operation region, IBRs continue to Ride-through, though they are briefly allowed to enter the current block mode if necessary to avoid tripping off from the grid. The drafting team takes into consideration the physical operational capability of the power electronics devices under such low voltage conditions. However, the IBR facility shall restart current exchange in less than or equal to five cycles of positive sequence voltage returning to the continuous operation region or mandatory operation region. If the interconnecting entity has performance requirements that are more stringent than the standard, the Generator Owner should follow the requirements set by the interconnecting entity.

Rationale for Requirement R2.4

This subpart of Requirement R2 ensures when a fault is cleared on the transmission system, the voltage regulators of connected IBRs must adjust the reactive current injection to restore the transmission system voltage to the pre-disturbance voltage as defined by the automatic voltage regulator (AVR) setpoint. The drafting team acknowledges that tuning of the AVR requires a balance between multiple competing physical factors, e.g., rise time, overshoot, and transient stability. However, it is anticipated that IBR controls will be tuned to allow for a stable post-disturbance voltage recovery without causing excessive overshoot or undershoot of the setpoint. When such overshoots do occur, they must not exceed the magnitude and duration of the applicable table given in **Attachment 1**. Furthermore, this standard anticipates that control system tuning to prevent such over/under voltages will focus on the speed at which the controller responds to setpoint changes rather than on the magnitude of the reactive current response. For example, reductions in k-factor to prevent over/under voltages should only be considered as a last resort.

Rationale for Requirement R2.5

This subpart of Requirement R2 ensures that the IBR returns to effective pre-disturbance operation unless otherwise specified or needed by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Rationale for Requirement R3

The objective of Requirement R3 is to ensure that IBRs Ride -through frequency excursion events with magnitude and time durations as defined in Attachment 2.

Grid frequency reflects the balance of system generation and load. A system event that causes a generation/load imbalance will cause system frequency to deviate from nominal. The system may experience an over-frequency event (in the case of more generation than load) or an under-frequency event (in the case of less generation than load). Inertia resists the deviation from nominal frequency, giving the operators additional time to rebalance generation and load. System inertia depends on the amount of rotating mass connected to the system (such as the synchronous generators or motors). The larger the system inertia, the slower the system frequency will deviate from the nominal value and the lower the grid Rate Of Change Of Frequency (ROCOF), giving more time to try to rebalance generation and load. Also, higher system inertia may minimize the risk of Cascading generation loss caused by the operation of generator frequency protection.

A reduction in system inertia is an inevitable consequence of a power system transiting toward more IBR and less synchronous generators. As discussed in the previous paragraph, less system inertia means the frequency will deviate from the nominal value more quickly during a generation/load imbalance event and will expose the system to a higher ROCOF. A wider frequency Ride-through capability for IBR may be required to avoid the risk of widespread tripping. To reduce the risk of widespread IBR tripping during frequency disturbances, and more generally to ensure the reliability of future grids with high IBR penetration, the drafting team proposes a 6-second frequency Ride-through capability requirement for frequencies in the ranges of 61.8Hz to 64Hz or 57.0Hz to 56.0Hz range. The proposed 6-second time frame of the frequency Ride-through capability requirement is beyond the IEEE 2800 standard frequency Ride-through requirement and beyond frequency Ride-through requirements for synchronous machines under PRC-024.

IBRs lack the inertia and short circuit contributions of synchronous machines. To compensate for the lack of inertia and short circuit contributions, they should have wider tolerances for frequency and voltage excursions to meet the needs of future power systems with a higher percentage of IBR. Synchronous resources are more sensitive to frequency deviations than IBR resources. All IBR resources (except for type 3 wind turbines) interface to the grid through fast switching of power electronics devices. These power electronic devices are much less sensitive to the transmission system frequency excursion than non-hydraulic turbine synchronous resources (steam turbines and combustion turbines). In the case of the non-hydraulic turbine synchronous resources, the turbine is usually considered to be more restrictive than the generator in limiting IBR frequency Ride-through because of possible mechanical resonances in the many stages of turbine blades. Off-nominal frequencies may bring blade vibrational frequencies closer to a mechanical resonate frequency and cause damage due to the vibration stresses. However, inverter-interfaced-IBR does not share this vibrational failure mode. Therefore, IBR should be capable of riding through the increased proposed 6-second frequency Ride-through requirement without risk of equipment damage or need for frequency protection to operate.

Requirement R3 does not prescribe specific frequency protection settings for IBR equipment. IBR frequency protection settings should only be set to protect the IBR from damage caused by operation at off-nominal frequency. An IBR owner must ensure that the IBR frequency protection does not prevent an IBR from meeting the R3 Ride-through requirement.

This standard requires that IBRs remain electrically connected and continue to exchange current during a frequency excursion event in which the frequency remains within the must Ride-through zone according to **Attachment 3** and while the absolute ROCOF magnitude is less than or equal to 5 Hz/second. Some IBR controllers and their ability to remain electrically connected and continue to exchange current with the grid are sensitive to ROCOF during a frequency excursion event. If needed to maintain the stability of the IBR or prevent equipment damage, the R3 requirement allows the IBR to trip for an absolute ROCOF exceeding 5Hz/sec within the must Ride-through zone of **Attachment 2**. Failure to Ride-through due to ROCOF exceeding 5Hz/sec shall only be allowed during a generator/load imbalance event that causes the frequency to deviate from nominal.

To minimize the misoperation tripping of the IBR on the ROCOF setting, the rate of change of frequency (ROCOF) must be calculated as the average rate of change over multiple calculated system frequencies for some time greater than or equal to 0.1 seconds. The ROCOF calculation is not applicable during the fault occurrence and clearance (i.e., protection should not trip due to any perceived ROCOF during the entire disturbance and recovery period) and should not operate at the onset of a fault, during a fault, or at fault clearance, i.e., it should be disabled during faults. The IBR shall Ride-through any system disturbance while the voltage at the high-side of the main power transformer remains within the must Ride-through zones as specified in **Attachment 1**. The ROCOF measurement should begin after fault clearance and is only applicable for generation/load imbalance disturbances such as a system separation, an island condition, or the loss of a large load or generator.

Rationale for Requirement R4

The objective of Requirement R4 is to ensure legacy IBR (IBR existing as of the enforcement date of PRC-029-1) are able to obtain an exemption to the voltage Ride-through requirements if hardware replacements or other costly upgrades would be necessary to comply with Requirements R1 or Requirement R2. This provision allows such exemptions as long as such limitations are documented and communicated to the Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator of the respective footprints in which the IBR project is located. The Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator will then need to take the voltage Ride-through limitations into account in planning and operations.

Limitations must not be construed as complete exemptions from the applicable **Attachment 1** table but must be specific as to which voltage band(s) and associated duration(s) cannot be satisfied or specific as to the number of cumulative voltage deviations within a ten-second time period that the equipment can Ride-through if less than four. Limitation descriptions should identify the specific equipment and explain the characteristic(s) of that equipment that prevent Ride-through. If any equipment limitation is removed or otherwise corrected, it is likewise necessary to communicate to the Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator of this.

FERC Order No. 901 states that this provision would be limited to exempting “certain registered IBRs from voltage Ride-through performance requirements.” This is the reason that no similar provisions are included for exemptions for frequency or ROCOF Ride-through requirements per R3.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Technical Rationale

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

PRC-029-1 – Frequency and Voltage Ride-Through Requirements for Inverter-Based Generating Resources

General Rationale

The drafting team has created a new Reliability Standard (PRC-029-1) to address inverter-based resource (IBR) disturbance ~~r~~Ride-through performance criteria. This proposal is a consequence of both the different natures of synchronous and inverter-based generation resources and several recent events exhibiting significant IBR R~~r~~ide-through deficiencies. The proposed PRC-029-1 coincides with certain ~~r~~Ride-through requirements of IEEE 2800-2022 but is structured to follow language from FERC Order No. 901, which states that "NERC has the discretion to consider during its standards development process whether and how to reference IEEE standards in the new or modified Reliability Standards."[1]

The lack of standardization of IBR technology (equipment/controller behavior) has created reliability challenges associated with the interconnection of IBR facilities to the power grid. The nature of the fast switching of power electronics of IBR generation and the electronic interface to the transmission system is such that disturbance ~~r~~Ride-through behavior is largely determined by manufacturer-specific equipment and controls system designs. These controls may be programmed but also have more restrictive limits on current, both in magnitude and duration. IBR responses to grid disturbances are highly controlled and managed by using fast switching of power electronics devices dependent upon manufacturer specific control system design that can be programmed in many ways and with various and concurrent R~~r~~ide-through performance objectives. Rather than attempting to restrict the myriad of control approaches, protections, and settings, it is more straightforward to require ~~r~~Ride-through during defined frequency and voltage excursions.

In contrast to synchronous generation, the need for IBR R~~r~~ide-through requirements has been heightened by recent events during which IBRs have not met PRC-024-3 frequency and voltage ~~r~~Ride-through expectations, often due to controls and protection only indirectly associated with the system voltage and frequency excursions. In addition to R~~r~~ide-through, there is the question of what IBRs should be doing as they R~~r~~ide-through. IBR responses to system disturbances can be beneficial or detrimental to both their own R~~r~~ide-through and system reliability, often depending on adjustable control settings. Thus, it is essential to set expectations on performance during R~~r~~ide-through as well as ~~r~~Ride-through capability.

A further reason for proposing a separate IBR standard is that IBRs do not provide inertia or short circuit contributions, unlike synchronous machines. The drafting team thinks that IBR should compensate for their lack of inertia and short circuit contributions with wider tolerances for frequency and voltage

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excursions. This is the reason for the differences in the frequency and voltage tables and graphs between the ~~two~~ PRC-024-4 and PRC-029-1 standards.

The proposed PRC-029-1 must be understood generally as an event-based standard though it is also required to provide evidence of the ability to ~~r~~Ride-through disturbance events by means of dynamic models and simulation results. Compliance with PRC-029-1 is determined chiefly though not exclusively from IBR R~~r~~ide-through performance during transmission system events in the field. An IBR becomes noncompliant with PRC-029-1 when an event in the field occurs that shows that one or more requirements were not satisfied. This intent is clarified by *Operations Assessment* as the Time Horizon designation of requirements R1-R5.

FERC Order No. 901 Directives

PRC-029-1 is proposed in consideration of directives from FERC Order No. 901 that were assigned to the Project 2020-02 drafting team. The following directives were assigned to this drafting team for inclusion in this Standards Project (paragraph numbers of the FERC Order are included for reference):

- Paragraph 190: "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults."
- Paragraph 190: "The new or modified Reliability Standards must require registered IBRs to continue to inject current and perform frequency support during a Bulk-Power System disturbance."
- Paragraph 190: "Any new or modified Reliability Standard must also require registered IBR generator owners and operators to prohibit momentary cessation in the must ride-through zone during disturbances."
- Paragraph 190: "NERC must submit new or modified Reliability Standards that establish IBR performance requirements, including requirements addressing frequency and voltage ride through, post-disturbance ramp rates, phase lock loop synchronization, and other known causes of IBR tripping or momentary cessation."
- Paragraph 193: "Therefore, we direct NERC through its standard development process to determine whether the new or modified Reliability Standards should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements."
- Paragraph 193: "Further, we direct NERC to ensure that any such exemption would be applicable for only existing equipment that is unable to meet voltage ride-through performance. When such existing equipment is replaced, the exemption would no longer apply, and the new equipment must comply with the appropriate IBR performance requirements specified in the Reliability Standards (e.g., voltage and frequency ride through, phase lock loop, ramp rates, etc.)."

- Paragraph 193: "Finally, we direct NERC, through its standard development process, to require the limited and documented exemption list (i.e., IBR generator owner and operator exemptions) to be communicated with their respective Bulk-Power System planners and operators (e.g., the IBR generator owner's or operator's planning coordinator, transmission planner, reliability coordinator, transmission operator, and balancing authority)."
- Paragraph 199: "Pursuant to section 215(d)(5) of the FPA, we modify the NOPR proposal. To the extent NERC determines that a limited and documented exemption for those registered IBRs currently in operation and unable to meet voltage ride-through requirements is appropriate due to their inability to modify their coordinated protection and control settings, we direct NERC to develop new or modified Reliability Standards to mitigate the reliability impacts to the Bulk-Power System of such an exemption."
- Paragraph 208: "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop and submit to the Commission for approval new or modified Reliability Standards that require post-disturbance ramp rates for registered IBRs to be unrestricted and not programmed to artificially interfere with the resource returning to a pre-disturbance output level in a quick and stable manner after a Bulk-Power System."
- Paragraph 209: "The proposed new or modified Reliability Standards must require registered IBRs to ride through momentary loss of synchronism during Bulk-Power System disturbances and require registered IBRs to continue to inject current into the Bulk-Power System at pre-disturbance levels during a disturbance, consistent with the IBR Interconnection Requirements Guideline and Canyon 2 Fire Event Report recommendations."
- Paragraph 209: "Related to ACP/SEIA's comment recommending to revise the directive to require generators to maintain synchronism where possible and continue to inject current to support system stability, we direct NERC, through its standard development process, to consider whether there are conditions that may limit generators to maintain synchronism."
- Paragraph 209: "We direct NERC to submit to the Commission for approval new or modified Reliability Standards that would require registered IBRs to ride through any conditions not addressed by the proposed new or modified Reliability Standards that address frequency or voltage ride through, including phase lock loop loss of synchronism."
- Paragraph 226: "Further, we believe that there is a need to have all of the directed Reliability Standards effective and enforceable well in advance of 2030 and direct NERC to ensure that the associated implementation plans sequentially stagger the effective and enforceable dates to ensure an orderly industry transition for complying with the IBR directives in this final rule prior to that date." (*pertains multiple projects*)

Rationale for Applicability Section (4.0)

Functional Entities (4.1)

The functional entity responsible for assuring acceptable ~~r~~Ride-through performance of IBR is ~~either~~ the Generator Owner (GO)~~ or, in the case of High-voltage Direct Current (VSC-HVDC) transmission facilities that are dedicated connections for IBR inverter-based resources to the BPS, the Transmission Owner (TO)~~.

Facilities (4.2)

Applicability Facilities include~~s~~ only ~~those~~ IBR that also meet NERC registration criteria. Language used within PRC-029-1 applicability only refers to IBR as a whole plant/facility. Consistent with FERC Order No. 901, IBR performance is based on the overall IBR plant and disturbance monitoring equipment requirements established under the proposed PRC-028-1. Requirements within PRC-029-1 do not apply to individual inverter units or measurements taken at individual inverter unit terminals.

Rationale for Requirement R1

The objective of Requirement R1 is to ensure that all applicable IBRs will R~~r~~ide through grid voltage disturbances consistent with the must R~~r~~ide-through zone and operation regions specified in **Attachment 1**. IBRs must be able to demonstrate r~~r~~ide-through performance, that they remain electrically connected, i.e., shall not trip, and continue to exchange current, i.e., shall not enter momentary cessation.

The drafting team determined that the definition of "must R~~r~~ide-through zones" and "operation regions" should be consistent with those terms as used within IEEE 2800-2022. Additionally, the team determined that the voltage thresholds of each operation region should be based on measurements taken on the high-side of the main power transformer in PRC-029-1, also consistent with IEEE 2800-2022.

Battery Energy Storage Systems (BESS) units also must comply with Requirement R1 in all operating modes including charging, discharging, and idle (energized but not charging or discharging). A BESS in idle mode must be capable of responding to system voltage and frequency excursions as it does in charging or discharging modes.

Exceptions to **Attachment 1** performance criteria are allowable when 1) an IBR needs to trip to clear a fault~~ within its zone of protection~~, ~~and~~ 2) voltage at the high-side of the main power transformer goes outside an accepted~~2)~~ and a documented equipment limitation established in accordance with~~prevents an IBR from riding through the disturbance as permitted under~~ Requirement R4, 3) instantaneous positive sequence voltage phase angle jumps more than 25 electrical degrees at the high-side of the main power transformer initiated by a non-fault switching events occur on the transmission system, or 4) volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

When a grid disturbance occurs, such as a close-in fault or a relatively large switching event, the grid voltage may experience a rapid phase angle shift. In such cases, the phase displacement $\Delta\theta$ can be large enough to pose challenges for the phase lock loop (PLL) to track the terminal voltage, cause control instability within the inverter, such as the inner current control loop or the DC link control loop, and even lead to tripping of the inverter due to the malfunction of the controls.

Since phase angle jumps are common occurrences on the BPS, this standard requires the IBR to be designed and operated to ride-through a minimum phase angle jump of 25 electrical degrees. This is a typical value and aligns with the requirement in IEEE 2800~~-~~-2022.

Some IBR equipment has PLL loss of synchronism protection, referring to a protective function that operates when the angle displacement $\Delta\theta$ exceeds a threshold for a predetermined period of time (on the order of a couple of milliseconds). Historically, this protection has been used by some inverter manufacturers, especially for inverters in distribution systems. For the IBR connected to the BPS, this protection function should be disabled. If it is enabled, the phase angle jump protection setting should be configured such that the IBR shall only trip to prevent equipment damage.

Rationale for Requirement R2

In addition to having minimum voltage ~~r~~Ride-through capability specified in Requirement R1, all applicable IBRs are also required to adhere to certain voltage ~~r~~Ride-through performance criteria during system disturbances. Acceptable performance criteria depend on the operation region that an IBR is presently in or when in transition from one operation region to another operation region. Requirement R2 includes specific performance criteria and is needed to assure consistent IBR performance within and each operation region in **Attachment 1** and when in transition between regions.

Rationale for Requirement R2.1

This subpart of Requirement R2 ensures, when the voltage at the high-side of the main power transformer (MPT) recovers to the ~~C~~continuous ~~O~~operation ~~R~~region from either the ~~M~~mandatory ~~O~~operation r~~R~~egion or the p~~P~~ermissive ~~O~~operation ~~R~~region, an IBR is expected to deliver the pre-disturbance level of ~~active~~ Real ~~p~~Power or available ~~active~~ Real ~~p~~Power, whichever is less. Available Real Power allows for changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes attributed to IBR tripping in whole or part. This requires an IBR to exit the “High Voltage Ride Through (HVRT)” or “Low Voltage Ridge Through (LVRT)” modes properly such that it does not cause reduction in the ~~active~~ Real ~~p~~{ower when the system already recovers the voltage within the ~~C~~continuous ~~O~~operation ~~R~~region.

When the voltage at the high-side of the MPT is greater than 0.9 per-unit and less than 0.95 per-unit, IBRs are expected to exit the LVRT mode and come back to “normal operating mode”. If an IBR has a default total current limit of 1.0 per-unit, the apparent power production of an IBR will be limited to be below 1.0 per-unit (e.g., the per-unit value of IBR terminal voltage). In such case, IBR needs to configure a preference setting, either to maintain pre-disturbance ~~active~~ Real P~~p~~ower or maximize the ~~r~~Reactive ~~p~~Power in order to further help with voltage recovery, or according to requirements specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Rationale for Requirement R2.2

This subpart of Requirement R2 ensures when the voltage at the high-side of the MPT is within the ~~M~~mandatory o~~O~~peration ~~R~~region, IBRs ~~are expected to enter the HVRT and LVRT mode such that it will~~ inject or absorb reactive current proportional to the level of terminal voltage deviations it measures. IBR shall follow Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specified certain magnitude of R~~r~~eactive P~~p~~ower response to voltage changes, if available.

By default, reactive current prioritization shall be configured unless Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires ~~active~~ Real ~~p~~Power priority.

Rationale for Requirement R2.3

This subpart of Requirement R2 ensures that when the voltage at the high-side of the MPT is within the permissive operation region, IBRs continue to Ride-through, through they are briefly allowed to enter the current block mode if necessary to avoid tripping off from the grid. The drafting team takes into consideration the physical operational capability of the power electronics devices under such low voltage conditions. However, the IBR facility shall restart current exchange in less than or equal to five cycles of positive sequence voltage retraining to a continuous operation region or mandatory operation region. If the interconnecting entity has performance requirements that are more stringent than the standard, the Generator Owner should follow the requirements set by the interconnecting entity.

Rationale for Requirement R2.4

This subpart of Requirement R2 ensures when a fault is cleared on the transmission system, the voltage regulators of connected IBRs must adjust the reactive current injection to restore the transmission system voltage to the pre-disturbance voltage as defined by the automatic voltage regulator (AVR) setpoint. The drafting team acknowledges that tuning of the AVR requires a balance between multiple competing physical factors, e.g., rise time, overshoot, and transient stability. However, it is anticipated that IBR controls will be tuned to allow for a stable post-disturbance voltage recovery without causing excessive overshoot or undershoot of the setpoint. When such overshoots do occur, they must not exceed the magnitude and duration of the applicable table given in **Attachment 1**. Furthermore, this standard anticipates that control system tuning to prevent such over/under voltages will focus on the speed at which the controller responds to setpoint changes rather than on the magnitude of the reactive current response. For example, reductions in k-factor to prevent over/under voltages should only be considered as a last resort.

Rationale for Requirement R2.5

This subpart of Requirement R2 ensures that IBR returns to effective pre-disturbance operation unless otherwise specified or needed by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

~~Must Ride-through~~

Rationale for Requirement R3

The objective of Requirement R3 is to ensure that IBRs remain electrically connected, synchronized, and exchanging current, that is, continuing to operate during a frequency excursion event.

Grid frequency reflects the balance of system generation and load. A system event that causes a generation/load imbalance will cause system frequency to deviate from nominal. The system may experience an over-frequency event (in the case of more generation than load) or an under-frequency event (in the case of less generation than load). Inertia resists the deviation from nominal frequency, giving the operators additional time to rebalance generation and load. System inertia depends on the amount of rotating mass connected to the system (such as the synchronous generators or motors). The larger the system inertia, the slower the system frequency will deviate from the nominal value and the lower the grid Rate Of Change Of Frequency (ROCOF), giving more time to try to rebalance generation and load. Also, higher system inertia may minimize the risk of Cascading generation loss caused by the operation of generator frequency protection.

A reduction in system inertia is an inevitable consequence of a power system transiting toward more IBR and less synchronous generators. As discussed in the previous paragraph, less system inertia means the frequency will deviate from the nominal value more quickly during a generation/load imbalance event and will expose the system to a higher ROCOF. A wider frequency ride-through capability for IBR may be required to avoid the risk of widespread tripping. To reduce the risk of widespread IBR tripping during frequency disturbances, and more generally to ensure the reliability of future grids with high IBR penetration, the drafting team proposes a 6-second frequency R~~r~~ide-through capability requirement for frequencies in the ranges of 61.8Hz to 64Hz or 57.0Hz to 56.0Hz range. The proposed 6-second time frame of the frequency R~~r~~ide-through capability requirement is beyond the IEEE 2800 standard frequency ride-through requirement and beyond frequency ~~r~~Ride-through requirements for synchronous machines under PRC-024.

IBRs lack the inertia and short circuit contributions of synchronous machines. To compensate for the lack of inertia and short circuit contributions, they should have wider tolerances for frequency and voltage excursions to meet the needs of future power systems with a higher percentage of IBR. Synchronous resources are more sensitive to frequency deviations than IBR resources. All IBR resources (except for type 3 wind turbines) interface to the grid through fast switching of power electronics devices. These power electronic devices are much less sensitive to the transmission system frequency excursion than non-hydraulic turbine synchronous resources (steam turbines and combustion turbines). In the case of the non-hydraulic turbine synchronous resources, the turbine is usually considered to be more restrictive than the generator in limiting IBR frequency ride-through because of possible mechanical resonances in the many stages of turbine blades. Off-nominal frequencies may bring blade vibrational frequencies closer to a mechanical resonate frequency and cause damage due to the vibration stresses. However, inverter-interfaced-IBR does not share this vibrational failure mode. Therefore, IBR should be capable of riding through the increased proposed 6-second frequency ride-through requirement without risk of equipment damage or need for frequency protection to operate.

Requirement R3 does not prescribe specific frequency protection settings for IBR equipment. IBR frequency protection settings should only be set to protect the IBR from damage caused by operation at off-nominal frequency. An IBR owner must ensure that the IBR frequency protection does not prevent an IBR from meeting the R3 ride-through requirement.

This standard requires that IBRs remain electrically connected and continue to exchange current during a frequency excursion event in which the frequency remains within the must R~~r~~ide-through zone according to **Attachment 3** and while the absolute ROCOF magnitude is less than or equal to 5 Hz/second. Some IBR controllers and their ability to remain electrically connected and continue to exchange current with the grid are sensitive to ROCOF during a frequency excursion event. If needed to maintain the stability of the IBR or prevent equipment damage, the R3 requirement allows the IBR to trip for an absolute ROCOF exceeding 5Hz/sec within the must R~~r~~ide-through zone as shown in **Attachment 2**. Failure to R~~r~~ide-through due to ROCOF exceeding 5Hz/sec shall only be allowed during a generator/load imbalance event that causes the frequency to deviate from nominal.

To minimize the misoperation tripping of the IBR on the ROCOF setting, the rate of change of frequency (ROCOF) must be calculated as the average rate of change over multiple calculated system frequencies for some time greater than or equal to 0.1 seconds. The ROCOF calculation is not applicable during the fault occurrence and clearance (i.e., protection should not ~~operate~~ trip due to any perceived ROCOF~~at the onset of a fault~~, during ~~a~~the entire disturbance and recovery period) and should not operate at the onset of a fault, during a fault, or at fault clearance, i.e., it should be disabled for faults. The IBR shall R~~r~~ide-through any system disturbance while the voltage at the high~~-~~-side of the main power transformer remains within the must ride-through zones as specified in **Attachment 1**.The ROCOF measure should begin after fault clearance and is only applicable for generation/load imbalance disturbances such as a system separation, an island condition, or the loss of a large load or generator ~~Furthermore, to reduce the risk of IBR tripping on ROCOF protection, ROCOF shall be calculated as the average rate of change for multiple calculated system frequencies for some time greater than or equal to 0.1 seconds~~.

Rationale for Requirement R4

The objective of Requirement R4 is to ensure legacy IBR (IBR existing as of the enforcement date of PRC-029-1) are able to obtain an exemption to the voltage ~~r~~Ride-through requirements if hardware replacements or other costly upgrades would be necessary to comply with Requirements R1 or Requirement R2. This provision allows such exemptions as long as such limitations are documented and communicated to the Planning Coordinator, Transmission Planner, ~~and~~ Reliability Coordinator, and Transmission Operator of the respective footprints in which the IBR project is located. The Planning Coordinator, Transmission Planner, ~~and~~ Reliability Coordinator, and Transmission Operator will then need to take the voltage ~~r~~Ride-through limitations into account in planning and operations.

Limitations must not be construed as complete exemptions from the applicable **Attachment 1** table but must be specific as to which voltage band(s) and associated duration(s) cannot be satisfied or specific as to the number of cumulative voltage deviations within a ten-second time period that the equipment can ride-through if less than four. Limitation descriptions should identify the specific equipment and explain the characteristic(s) of that equipment that prevent ride-through. If any equipment limitation is removed or otherwise corrected, it is likewise necessary to communicate to the Planning Coordinator, Transmission Planner, ~~and~~ Reliability Coordinator, and Transmission Operator of this.

FERC Order No. 901 states that this provision would be limited to exempting “certain registered IBRs from voltage ride-through performance requirements.” This is the reason that no similar provisions are included for exemptions for frequency or rate-of-change-of-frequency (ROCOF) ride-through requirements per R3.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2020-02 Modifications to PRC-024 (Generator Ride-through) | PRC-029-1

This document provides the drafting team's (DT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-029-1. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The DT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Power System (BPS) instability, separation, or a cascading sequence of failures, or could place the BPS at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to BPS instability, separation, or a cascading sequence of failures, or could place the BPS at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the BPS, or the ability to effectively monitor and control the BPS. However, violation of a medium risk requirement is unlikely to lead to BPS instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BPS, or the ability to effectively monitor, control, or restore the BPS. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BPS instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the BPS, or the ability to effectively monitor and control the BPS; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BPS, or the ability to effectively monitor, control, or restore the BPS.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the BPS. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BPS:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for PRC-029-1, Requirement R1	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate as applicable generating resources must be able to ride-through system disturbances. Failure to ride-through has been documented in multiple NERC reports leading to exacerbated system conditions, resulting in the electrical disconnecting of additional generation and widespread outages.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Similar requirements in PRC-024-3 are identified as Medium but are based on equipment protection setting documentation rather than actual, recorded performance during a grid disturbance. Therefore, this VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner failed to demonstrate the design capability of each applicable IBR to Ride-through in accordance with Attachment 1, except for those conditions identified in Requirement R1.	N/A	N/A	The Generator Owner failed to demonstrate each applicable IBR adhered to Ride-through requirements in accordance with Attachment 1, except for those conditions identified in Requirement R1.

VSL Justifications for PRC-029-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R1	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R2	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate as applicable generating resources must be able to ride-through system disturbances. Failure to ride-through has been documented in multiple NERC reports leading to exacerbated system conditions, resulting in the electrical disconnecting of additional generation and widespread outages.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Similar requirements in PRC-024-3 are identified as Medium but are based on equipment protection setting documentation rather than actual, recorded performance during a grid disturbance. Therefore, this VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-029-1, Requirement R2	
Proposed VRF	**High**
Definitions of VRFs	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner failed to demonstrate the design capability of each applicable IBR to adhere to performance requirements during voltage excursions, as specified in Requirement R2.	N/A	N/A	The Generator Owner failed to demonstrate each applicable IBR adhered to performance requirements during voltage excursions, as specified in Requirement R2.

VSL Justifications for PRC-029-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R2	
Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R3	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of High is appropriate that if violated, it would be expected to adversely affect the electrical state or capability of the BPS.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner IBR to demonstrate the design capability of each applicable IBR to Ride-through in accordance with	N/A	N/A	The Generator Owner IBR to demonstrate each applicable IBR adhered to Ride-through requirements in accordance with

Attachment 2.			Attachment 2.

VSL Justifications for PRC-029-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R4	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate that if violated, it would not be expected to adversely affect the electrical state or capability of the BPS.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of Lower VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a Lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and CEA more than 90 calendar days but less than or equal to 120 calendar days after the change to the hardware. OR The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 12 months but less than or equal to 15 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 90 days but less than or equal to 120 days after receiving a request for additional information	The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 120 calendar days but less than or equal to 150 calendar days after the change to the hardware. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 120 days but less than or equal to 150 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.	The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 150 calendar days but less than or equal to 180 calendar days after the change to the hardware. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 150 days but less than or equal to 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.	The Generator Owner failed to document complete information for IBR identified with known hardware limitations that prevent the IBR from meeting voltage Ride-through criteria as detailed in Requirements R1 or R2. OR The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s),Reliability Coordinator(s), and CEA more than 180 calendar days after the change to the hardware. OR The Generator Owner failed to provide a copy to the applicable entities as detailed in Requirement R4.2 within 24 months after the effective date of Requirement R4. OR

VSLs for PRC-029-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
by an entity listed in Requirement R4.2.1.			The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.

VSL Justifications for PRC-029-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R4	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

Violation Risk Factor and Violation Severity Level Justifications

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
PRC-029-1

This document provides the drafting team's (DT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-029-1. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The DT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to Bulk Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System. However, violation of a medium risk requirement is unlikely to lead to Bulk- Power System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Power System, or the ability to effectively monitor, control, or restore the Bulk Power System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for PRC-029-1, Requirement R1	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate as applicable generating resources must be able to ride-through system disturbances. Failure to ride-through has been documented in multiple NERC reports leading to exacerbated system conditions, resulting in the electrical disconnecting of additional generation and widespread outages.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Similar requirements in PRC-024-3 are identified as Medium but are based on equipment protection setting documentation rather than actual, recorded performance during a grid disturbance. Therefore, this VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner ~~or Transmission Owner~~ failed to demonstrate the design capability of each applicable ~~facility~~ IBR to Ride-through in accordance with Attachment 1, except for those conditions identified in Requirement R1.	N/A	N/A	The Generator Owner ~~or Transmission Owner~~ failed to demonstrate each applicable ~~facility~~ IBR adhered to Ride-through requirements in accordance with Attachment 1, except for those conditions identified in Requirement R1.

VSL Justifications for PRC-029-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R1	
Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R2	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate as applicable generating resources must be able to ride-through system disturbances. Failure to ride-through has been documented in multiple NERC reports leading to exacerbated system conditions, resulting in the electrical disconnecting of additional generation and widespread outages.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Similar requirements in PRC-024-3 are identified as Medium but are based on equipment protection setting documentation rather than actual, recorded performance during a grid disturbance. Therefore, this VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner ~~or Transmission Owner~~ failed to demonstrate the design capability of each applicable ~~facility~~ IBR to adhere to performance requirements during voltage excursions, as specified in Requirement R2.	N/A	N/A	The Generator Owner ~~or Transmission Owner~~ failed to demonstrate each applicable ~~facility~~ IBR adhered to performance requirements during voltage excursions, as specified in Requirement R2.

VSL Justifications for PRC-029-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R2	
Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R3	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of High is appropriate that if violated, it would not be expected to adversely affect the electrical state or capability of the Bulk-Power System.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner ~~or Transmission Owner~~ failed to demonstrate the design capability of each applicable ~~facility~~ IBR to Ride-through in accordance with Attachment 2.	N/A	N/A	The Generator Owner ~~or Transmission Owner~~ failed to demonstrate each applicable ~~facility~~ IBR adhered to Ride-through requirements in accordance with Attachment 2.

VSL Justifications for PRC-029-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore,

VSL Justifications for PRC-029-1, Requirement R3	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R4	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate that if violated, it would not be expected to adversely affect the electrical state or capability of the Bulk-Power System.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of Lower VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a Lower VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner ~~or Transmission Owner~~ with a previously communicated ~~equipment~~ hardware limitation that ~~repairs or~~ replaces the documented limiting hardware ~~equipment~~ but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and ~~Regional Entity~~CEA more than ~~3~~90 calendar days but less than or equal to ~~6~~120 calendar days after the change to the hardware~~equipment~~. OR The Generator Owner ~~or Transmission Owner~~ provided a copy to the applicable entities as detailed in Requirement R4.2 more than 12 months but less than or equal to 15 months after the effective date of Requirement R4.	The Generator Owner ~~or Transmission Owner~~ with a previously communicated hardware ~~equipment~~ limitation that ~~repairs or~~ replaces the documented limiting hardware ~~equipment~~ but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and ~~Regional Entity~~CEA more than ~~6~~120 calendar days but less than or equal to ~~9~~150 calendar days after the change to the hardware~~equipment~~. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 120 days but less than or equal to 150 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.	The Generator Owner ~~or Transmission Owner~~ with a previously communicated hardware ~~equipment~~ limitation that ~~repairs or~~ replaces the documented limiting hardware ~~equipment~~ but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s), and ~~Regional Entity~~CEA more than ~~9~~150 calendar days but less than or equal to 1~~2~~80 calendar days after the change to the hardware~~equipment~~. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 150 days but less than or equal to 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.	The Generator Owner ~~or Transmission Owner~~ failed to document complete information for ~~facilities~~ IBR identified with known hardware limitations that prevent the ~~facility~~ IBR from meeting voltage Ride-through criteria as detailed in Requirements R1 or R2. OR The Generator Owner ~~or Transmission Owner~~ with a previously communicated hardware ~~equipment~~ limitation that ~~repairs or~~ replaces the documented limiting hardware ~~equipment~~ but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and ~~Regional Entity~~CEA more than 1~~2~~80 calendar days after the change to the hardware~~equipment~~.

			OR The Generator Owner ~~or Transmission Owner~~ failed to provide a copy to the applicable entities as detailed in R4.2 within 24 months after the effective date of R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.

VSL Justifications for PRC-029-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R4	
Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

Standards Development Consideration of Directives from FERC Order 901

June 2024

Background

The Federal Energy Regulatory Commission (FERC) issued Order No. 901 on October 19, 2023, which includes directives on new or modified NERC Reliability Standard projects. Order No. 901 addresses a wide spectrum of reliability risks to the grid from the application of inverter-based resources (IBR); including both utility scale and behind the-meter or distributed energy resources. Within the Order, are four milestones that include sets of directives to NERC. The first milestone was achieved on January 17, 2024 as NERC filed its initial work plan to address all aspects of Order No. 901 throughout the next three years.[1] The filed work plan includes extensive detail on Standards Development approach and next steps to accomplish the suite of directives addressing IBR. The work plan was intended to be an initial roadmap to guide development for each of the Reliability Standards Projects identified as a 901-related project.

This document includes specifics for how each directive assigned to Project 2020-02 Modifications to PRC-024 (Generator Ride-through) drafting team have been addressed.

Resources

[FERC Order No. 901 – Final Rule Reliability Standards to Address Inverter-Based Resources]

[NERC Mapping Document for FERC Order 901 Directives to Standards Development Projects, Draft SARs, and Pending SARs]

[1] INFORMATIONAL FILING OF THE NORTH AMERICAN RELIABILITY CORPORATION REGARDING THE DEVELOPMENT OF RELIABILITY STANDARDS RESPONSIVE TO ORDER NO. 901; 01/17/2024; https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/NERC%20Compliance%20Filing%20Order%20No%20901%20Work%20Plan_packaged%20-%20public%20label.pdf

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
49	190	2	"Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	The new standard PRC-029-1 will require registered generator owners of IBRs to both design and operate their IBR plants to ride through voltage and frequency excursions within "must ride-through zones" according to how these zones are defined in the standard. The must ride-through zones are defined in terms of voltage and frequency magnitude and time duration. Tripping of IBR plants is permitted only outside of the defined must ride-through zones. The voltage and frequency must ride-through zones are based on IEEE 2800-2022 no-trip zones and are established in view of experience with voltage and frequency excursions in planning and operating criteria disturbances, under-frequency load shedding stages, reasonable and practical limits of IBR voltage and frequency tolerances, PRC-024-3 voltage and frequency relay setting graphs, and include adequate margins against worst-case conditions that could be brought about during system disturbances.
50	190	2	"The new or modified Reliability Standards must require registered IBRs to continue to inject current and perform frequency support during a Bulk-Power System disturbance."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	In association with the new PRC-029 standard, a definition of the term *ride-through* is proposed for addition to the NERC Glossary of Terms that essentially states that IBR facilities must remain connected and continue to fulfill their established control and regulation functions (which generally involve exchange of current) in order to qualify as riding through system disturbances. Support of frequency is predicated on, and to a large degree achieved by the riding through of system disturbances. Frequency regulation (or governing) is presently not a continent-wide necessity and not a requirement on individual generating

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
					plants/facilities in NERC standards. RTO/ISO requirements may apply.
51	190	2	"Any new or modified Reliability Standard must also require registered IBR generator owners and operators to prohibit momentary cessation in the no-trip zone during disturbances."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	Momentary cessation, understood as inverter temporary current blocking while still remaining connected, is restricted to only two system conditions: 1) non-fault line switching caused voltage phase angle jumps in excess of 25 degrees that could result in tripping unless the inverter goes into current blocking, and 2) while voltage at the plant-system interface is less than 0.10 per unit during which time it may be difficult or impractical to maintain current exchange.
52	190	2	"NERC must submit new or modified Reliability Standards that establish IBR performance requirements, including requirements addressing frequency and voltage ride through, post-disturbance ramp rates, phase lock loop synchronization, and other known causes of IBR tripping or momentary cessation."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	IBR frequency and voltage ride through requirements are established in the new PRC-029 standard as noted above. A default post-disturbance ramp rate of 1.0 second is specified unless a faster or slower rate is specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator to accommodate specific system post-disturbance recovery needs. Any Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specified ramp rate becomes the standard requirement. Tripping due to phase lock loop loss of synchronism is specifically not permitted within voltage and frequency must ride through zones.
53	193	2	"Therefore, we direct NERC through its standard development process to determine whether the new or modified Reliability	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	Exemption from the voltage must ride-through zone requirement of PRC-029-1 is permitted for IBR plants/facilities that are in service at the enforcement date of the standard. The IBR Generator Owner must document the need for an exemption and the documentation must explain what hardware prevents the IBR

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
			Standards should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements.”		from meeting the requirement and must be specific as to what aspect of the voltage must ride-through zone cannot be met. The Compliance Enforcement Authority checks that all aspects of the documentation specified in the standard have been provided by the GO and the GO is required to supply further information on the need for and the nature of the exemption if requested by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator. The implementation plan provides a 12-month time window for exemption requests to be submitted following the enforcement date. Following the 12-month window, further exemption requests will either not be accepted or could be considered an admission of non-compliance.
54	193	2	“Further, we direct NERC to ensure that any such exemption would be applicable for only existing equipment that is unable to meet voltage ride-through performance. When such existing equipment is replaced, the exemption would no longer apply, and the new equipment must comply with the appropriate IBR performance requirements specified in the Reliability Standards (e.g., voltage and frequency ride	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	The exemption provision of PRC-029-1 is available only for IBR plants/facilities that are in service at the enforcement date as noted above. The exemption provision also stipulates that once the plant/facility hardware causing the inability to comply with the voltage must ride-through requirement is replaced, the exemption is withdrawn (“no longer applies”).

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
			through, phase lock loop, ramp rates, etc.)."		
55	193	2	"Finally, we direct NERC, through its standard development process, to require the limited and documented exemption list (i.e., IBR generator owner and operator exemptions) to be communicated with their respective Bulk-Power System planners and operators (e.g., the IBR generator owner's or operator's planning coordinator, transmission planner, reliability coordinator, transmission operator, and balancing authority)."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	The exemption provision of PRC-029-1 requires an IBR Generator Owner to supply its exemption request documentation to its Transmission Planner, Planning Coordinator, Reliability Coordinator, and Transmission Operator within the 12-month window following the enforcement date as noted above.

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
56	199	2	"Pursuant to section 215(d)(5) of the FPA, we modify the NOPR proposal. To the extent NERC determines that a limited and documented exemption for those registered IBRs currently in operation and unable to meet voltage ride-through requirements is appropriate due to their inability to modify their coordinated protection and control settings, we direct NERC to develop new or modified Reliability Standards to mitigate the reliability impacts to the Bulk-Power System of such an exemption."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	Mitigation of the reliability impacts of voltage must ride-through exemptions are existing NERC standard responsibilities of Transmission Planners, Planning Coordinators, Reliability Coordinators, and Transmission Operators under TPL, IRO, TOP, and other standards. These entities may need to restrict the operation of exempted IBRs where and when their tripping may result in detrimental reliability impacts.
57	208	2	"Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop and submit to the Commission for approval new or modified Reliability Standards that require post-disturbance ramp rates for registered IBRs to be unrestricted and not	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	As indicated above, a default post-disturbance ramp rate of 1.0 second is specified unless a faster or slower rate is specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator to accommodate specific system post-disturbance recovery needs. Any Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specified ramp rate becomes the standard requirement.

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
			programmed to artificially interfere with the resource returning to a pre-disturbance output level in a quick and stable manner after a Bulk-Power System."		
59	209	2	"We direct NERC to submit to the Commission for approval new or modified Reliability Standards that would require registered IBRs to ride through any conditions not addressed by the proposed new or modified Reliability Standards that address frequency or voltage ride through, including phase lock loop loss of synchronism."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	Phase lock loop loss of synchronism is not allowed as a cause of tripping while voltage remains within the must ride-through zone unless there are phase jumps more than 25 degrees caused by non-fault switching events. A footnote under R1 also specifically states that phase lock loop loss of synchronism as not a permissible condition for tripping while voltage remains within the must ride-through zone.
60	209	2	"The proposed new or modified Reliability Standards must require registered IBRs to ride through momentary loss of synchronism during Bulk-Power System disturbances and require registered IBRs to continue to inject current into the Bulk-	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	As indicated above, tripping due to phase lock loop loss of synchronism is specifically not permitted within voltage and frequency must ride-through zones. The requirement to return to pre-disturbance power also includes a provision for return to "available active power" to allow for "changes of facility active power output attributed to factors such as weather patterns, change of wind, and change in irradiance," but "changes of facility active power attributed to IBR tripping in

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
			Power System at pre-disturbance levels during a disturbance, consistent with the IBR Interconnection Requirements Guideline and Canyon 2 Fire Event Report recommendations."		whole or part" are not permitted. Injecting current at pre-disturbance levels during a disturbance is not always practical or desirable. PRC-029-1 R2 specifies IBR required active and reactive power performance during voltage disturbances.
61	209	2	"Related to ACP/SEIA's comment recommending to revise the directive to require generators to maintain synchronism where possible and continue to inject current to support system stability, we direct NERC, through its standard development process, to consider whether there are conditions that may limit generators to maintain synchronism."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	IBRs are non-synchronous but can exhibit forms of instability other than loss of synchronism. System stability is a shared responsibility of Transmission Planners, Planning Coordinators, Reliability Coordinators, and Transmission Operators. IBR generation levels may need to be restricted by these entities to maintain system stability including IBR stability.
63A	226	2	"Further, we believe that there is a need to have all of the directed Reliability Standards effective and enforceable well in advance of 2030 and direct NERC to ensure that the associated implementation plans	Each of the identified Reliability Standards Projects in Milestone 2 will include implementation plans that assure	The PRC-029-1 implementation is a staggered implementation beginning twelve months following governmental approval with enforcement of all provisions within the twelve months following approval except as necessary to coordinate with the PRC-028-1 implementation plan that extends to 2030.

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
			sequentially stagger the effective and enforceable dates to ensure an orderly industry transition for complying with the IBR directives in this final rule prior to that date."	all new or modified Reliability Standards are effective and enforceable before 2030.	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2020-02 Modifications to PRC-024 (Generator Ride-through) | PRC-024-4 and PRC-029-1

Formal Comment Period Open through August 12, 2024

Now Available

A formal comment period for **PRC-029-1 - Frequency and Voltage Ride-through Requirements for Inverter-based Resources**, is open through **8 p.m. Eastern, Monday, August 12, 2024.**

This will be the last opportunity for NERC to ballot these projects through traditional mechanisms. The Board may take requisite action during the August 2024 Board of Trustees meeting to ensure directives are met.

The Standards Committee approved waivers to the Standard Processes Manual at their December 2023 meeting. These waivers were sought by NERC Standards staff for reduced formal comment and ballot periods. This will assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 901. *FERC Order 901 was issued under* Docket No. RM22-12-000 *on October 19, 2023.*

To assist industry in this upcoming comment and ballot period, NERC has released a Milestone 2 Summary that provides high-level overview of the current state of the associated projects and their interrelationships. The standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Note: PRC-024-4 passed the recent additional ballot (conducted June 28 – July 8, 2024). The drafting team will be moving this standard to a final ballot when the PRC-029-1 ballots open (August 2-12, 2024) as only non-substantive revision(s) were made.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Additional ballots for the standard and implementation plan, as well as the non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **August 2-12, 2024**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Manager of Standards Development, Jamie Calderon (via email) or at 404-960-0568 Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2020-02 Modifications to PRC-024 (Generator Ride-through) observer list” in the Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2020-02 Modifications to PRC-024 (Generator Ride-through) | PRC-029-1
Comment Period Start Date:	7/22/2024
Comment Period End Date:	8/12/2024
Associated Ballots:	2020-02 Modifications to PRC-024 (Generator Ride-through) Implementation Plan AB 3 OT 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-029-1 AB 3 ST

There were 70 sets of responses, including comments from approximately 159 different people from approximately 112 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the proposed definition of Ride-through? If not, please state what revision would be acceptable and why.

2. Do you agree with the changes made in this draft of PRC-029-1?

3. Provide any additional comments for the Drafting Team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO

MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	MRO,NPCC,RF,SERC,SPP RE,Texas RE,WECC	SRC 2024	Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	1	WECC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Greg Campoli	NYISO	1	NPCC
					Elizabeth Davis	PJM	2	RF
					Matt Goldberg	ISO New England	2	NPCC
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NPCC,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Jolly Hayden	East Texas Electric Cooperative, Inc.	NA - Not Applicable	Texas RE
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF

FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy- FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Micah Runner	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC

Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8, 9,10	NPCC	NPCC RSC	Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					David Kwan	Ontario Power Generation	4	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC

Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC
					Erin Wilson	NB Power	1	NPCC
					James Grant	NYISO	2	NPCC
					Michael Couchesne	ISO-NE	2	NPCC
					Kurtis Chong	IESO	2	NPCC
					Michele Pagano	Con Edison	4	NPCC
					Bendong Sun	Bruce Power	4	NPCC
					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Victoria Crider	Dominion Energy	3	NA - Not Applicable
					Sean Bodkin	Dominion Energy	6	NA - Not Applicable
					Steven Belle	Dominion Energy	1	NA - Not Applicable
					Barbara Marion	Dominion Energy	5	NA - Not Applicable
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

1. Do you agree with the proposed definition of Ride-through? If not, please state what revision would be acceptable and why.

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	No
Document Name	

Comment

Black Hills Corporation supports the comments provided by the NAGF which state: a. Recommend removing the word “entire” and the phase “in its entirety” from the proposed definition; b. adding the following revised language”…and continuing to operate through System Disturbances as defined in the applicable Reliaiblity Standards.”

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

Duke Energy agrees with and supports the following NAGF comment:

The NAGF does not agree with the proposed definition of Ride-through and provides the following recommendations for consideration:

a. Recommend removing the word “entire” and the phrase “in its entirety” from the proposed definition.

b. Recommend adding the following revised language “…and continuing to operate through System Disturbances as defined in the applicable Reliability Standards.”

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3

Answer	No
Document Name	

Comment

See EEi comments

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

1. We believe the addition of “in its entirety” is ambiguous and misplaced within the proposed definition. We propose the phrase should be moved to the end to imply the entire time duration of a Disturbance, from the start of the Disturbance to its return to pre-disturbance conditions.
2. We believe the addition of the term “System” should be removed from the definition. According to the NERC Glossary of Terms, the term is defined as “a combination of generation, transmission, and distribution components.” This proposed Reliability Standard only applies to Generator Owners, an entity that would not possess transmission and distribution asset components.
3. We believe the reference to the term “Disturbance” within the definition is too vague by itself. The proposed title of this Reliability Standard is “Frequency and Voltage Ride□through Requirements for Inverter□Based Resources.” The proposed purpose of this Reliability Standard is “to ensure that [Inverter□Based Resources] IBRs Ride-through to support the Bulk Power System (BPS) during and after defined frequency and voltage excursions.” Both imply any definition used in reference to this Reliability Standard should be narrowed to unplanned Frequency and Voltage events that produce abnormal system conditions or deviations to the electric system, as derived from term’s definition listed within the NERC Glossary of Terms. Therefore, we propose ending the “Ride□through” definition with the phrase “through the duration of a frequency or voltage Disturbance in its entirety, from its start to the return to pre-disturbance conditions.”

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

The NAGF does not agree with the proposed definition of Ride-through and provides the following recommendations for consideration:

a. Recommend removing the word “entire” and the phrase “in its entirety” from the proposed definition.

b. Recommend adding the following revised language “…and continuing to operate through System Disturbances as defined in the applicable Reliability Standards.”

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	

Constellation aligns with NAGF comments. Legacy inverters will not be able to ride through voltage and frequency events. It's important to include exemption for legacy inverters.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	

Capital Power supports the NAGF's comments:

The NAGF does not agree with the proposed definition of Ride-through and provides the following recommendations for consideration:

a. Recommend removing the word "entire" and the phrase "in its entirety" from the proposed definition.

b. Recommend adding the following revised language "…and continuing to operate through System Disturbances as defined in the applicable Reliability Standards."

Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	

NextEra believes that the definition of ride-through is too broad and does not directly tie back to voltage or frequency requirements. The word "entire" leaves too much room for interpretation of single IBR unit driving an unnecessary investigation.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

Constellation aligns with NAGF comments. Legacy inverters will not be able to ride through voltage and frequency events. It’s important to include exemption for legacy inverters.

Kimberly Turco on behalf of Constellation Energy Segments 5 and 6.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment

Minnesota Power (hereafter MP) agrees with EEI that the “ride-through” definition was clearer as proposed in IEEE 2800-2022.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

LG&E/KU agrees with EEI; there is no reason to deviate from the definition included in IEEE Std 2800-2022 and IEEE Std 1547-2018: “Ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified**.**” This definition makes it more clear that there are “limits” to Ride-through. The definition proposed by the DT implies that *any* tripping is failed Ride-through, even if the trip occurs for a condition where it is acceptable. Include the IEEE definition verbatim, there is no need for modification.

Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
"Please see EEI Comments"	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of the NAGF for Question 1.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	

Request clarification on the meaning of “in its entirety” and its intended purpose. Its inclusion adds confusion as the beginning of the definition already states “the entire plant/facility”. Does “in its entirety” apply to the entire facility, or the entire disturbance event?

Recommend “Ride-through: The entire plant/facility remaining connected to the Bulk Power System and continuing to operate through System Disturbances.”

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	

Comment

NIPSCO believes that the definition of ride-through is too broad and does not directly tie back to voltage or frequency requirements. The word “entire” leaves too much room for interpretation of single IBR unit driving an unnecessary investigation.

Likes 0	
Dislikes 0	

Response

Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

B. Ride-through definition

· Consider adopting definition from IEEE 2800, which is from IEEE 1547, and well understood by the industry.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	No
Document Name	

Comment	
Invenergy recommends removing “entire” and “in its entirety” from the proposed definition. As written, the definition attempts to prescribe an unreasonable interpretation of what ride-through should be from a system reliability perspective.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	
Invenergy recommends removing “entire” and “in its entirety” from the proposed definition. As written, the definition attempts to prescribe an unreasonable interpretation of what ride-through should be from a system reliability perspective.	
Likes 0	
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy does not believe it is necessary to add a glossary term for Ride-Through. Ride-through is an operational requirement that is defined by a set of magintudes and should remain defined within the requirements of the NERC Relaibility Standards, as traditionaly done.	
Likes 0	
Dislikes 0	
Response	
Srinivas Kappagantula - Arevon Energy - 5	
Answer	No
Document Name	
Comment	

Please refer to NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

MISO supports the comments of the ISO/RTO Council (IRC) Standards Review Committee (SRC).

In addition, we believe it is important to get the wording of the Ride-through definition accurate and clear. If the language is not clear (as to what is allowed/disallowed), it will likely lead to future disagreements.

One possible solution is to add the words "as specified" to the **Ride-through** definition to more explicitly tie the definition to the requirements under the proposed PRC-029 standard as shown below.

Ride□through: The entire plant/facility remaining connected to the Bulk Power System, and continuing in its entirety to operate as specified through the time□frame of System Disturbances.

This is only one possible approach to better capture the intent of the standard as described in the below excerpt from the **PRC-029-1 Technical Rationale, Rational for Requirement R3** (page 6) which references the need to remain synchronized, an important aspect to specify:

"The objective of Requirement R3 is to ensure that IBRs remain electrically connected, *synchronized*, and exchanging current, that is, continuing to operate during a frequency excursion event."

Likes 0	
Dislikes 0	
Response	
Jennifer Neville - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Support MRO NSRF comments	
Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own. In addition, ERCOT notes that revising the definition of the term “Ride-through” to recognize that the continued operation associated with ride-through needs to be maintained not just through the Disturbance but all the way through recovery to a new operating point would result in a clearer definition that better aligns with PRC-030, which provides that IBR unit losses (partial trips) are not allowed.

ERCOT supports the alternative definition of Ride-through that the SRC proposed, and ERCOT would also support revising that definition to read as follows: “Ride-through: The entire plant/facility **(including its dispersed power producing inverters)** remaining connected to the electric system and continuing in its entirety to operate in a manner that supports grid reliability through a System Disturbance, including the period of recovery back to a normal operating condition.”

Likes 0	
Dislikes 0	
Response	

Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

The definition of ride-through should be updated as follows: “The entire plant/facility remaining connected to the Bulk Power System and contininuing in its entirety to operate ***as specified*** *t*hrough System Disturbances ***inside defined limits***.

Likes 0	
Dislikes 0	
Response	

Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	

No Comment

Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no objections to the proposed definition of Ride-through definition.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
NRG Energy Inc is in support of the comments made by EPSA.	
Likes 0	
Dislikes 0	
Response	

Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI does not oppose the proposed definition of Ride-through.	
Likes 0	
Dislikes 0	
Response	
Nick Leathers - Ameren - Ameren Services - 3 - SERC	
Answer	Yes
Document Name	
Comment	
Ameren does not have any additional comments for consideration by the drafting team.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

Southern Company suggests using a different word or phrase for …“entire” plant/facility… to indicate that the expectation is that no equipment should drop out of service during the disturbance and remain connected throughout the disturbance. The use of the word “entire” could mean all plant equipment, including that which is already out of service for other reasons.

Suggested wording:
“The plant/facility shall remain connected and in service, maintaining the pre-distubance equipment configuration in operation, throughout the entirety of the system disturbance and recovery.”

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	Yes
Document Name	

Comment

While WECC voted Affirmative, WECC suggests the DT emphasize the nature of the definition may not allow a single turbine or solar array to be lost in a System Disturbance (equates to failed “Ride-through” with loss).

Likes 0	
Dislikes 0	

Response

Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	
Document Name	
Comment	
NRG agrees with and refers the SDT to the EPSA comments.	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,Texas RE,NPCC,SERC,RF, Group Name SRC 2024	
Answer	

Document Name	
Comment	

In the proposed definition of “Ride-through”, the ISO/RTO Council (IRC) Standards Review Committee (SRC) believes that the requirement that a facility continue “to operate” is inadequate; the definition needs to require the facility to maintain performance that is beneficial (or at the very least, not detrimental) to overall grid reliability.

It is preferable if the ride-through definition referred to the electric system instead of the BPS to be consistent with the IBR definition.

Finally, the concept of ride-through needs to recognize that the continued operation associated with ride-through needs to be maintained not just through the Disturbance but all the way through recovery to a new operating point. It is not clear that the existing Disturbance definition includes the recovery period.

To address these concerns, the ride-through definition could be revised to read as follows:

“Ride-through: The entire plant/facility remaining connected to the electric system and continuing in its entirety to operate in a manner that supports grid reliability through a System Disturbance, including the period of recovery back to a normal operating condition.”

Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 3,4,5,6

Answer	
Document Name	
Comment	

NCPA is not registered to vote on this item and thus is not opposing it or FERC Order 901.

Likes 0	
Dislikes 0	
Response	

2. Do you agree with the changes made in this draft of PRC-029-1?

Jennifer Neville - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Support MRO NSRF comments	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
We don't know if this proposal is going to improve reliability or the extent of reliability improvement, if any. The SDT has not shown us tangible relability improvement indices that support the modifications made. Considering this standard has been changed several times over the last few years we are skeptical that changes made will improve reliability. However, we do not oppose the proposal.	
Likes 0	
Dislikes 0	
Response	
Srinivas Kappagantula - Arevon Energy - 5	
Answer	No
Document Name	
Comment	
Please see SEIA and NAGF comments on these standards. Lack of exemptions for frequency ride through requirements especially for older legacy IBR facilities is critically important as some of these plants may not be able to comply with this standard.	
Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPC signed on to ACES comments:

It is the opinion of ACES that the definition of what constitutes an IBR should be consistent across the industry. The Project 2020-02 SDT has been working diligently towards this goal and we do not believe that an individual standard should deviate from their approach. Thus we recommend removing the phrase “The Elements associated with” from section 4.2 and modifying this section as follows:

4.2. Facilities:

4.2.1. Bulk Electric System (BES) IBRs; and

4.2.2. Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

R1. ACES believes that phrase “and is initiated by a non-fault switching event on the transmission system” should be struck from the 3rd bullet point of Requirement R1. It is our opinion that the GO will likely be unable to differentiate between an event initiated by a fault or an event initiated by a “non-fault switching event” on the Transmission system. In short, Transmission switching events are outside the purview of the GO.

R3/R4. ACES has grave concerns with the lack of any exceptions to Requirement R3 for existing IBRs. It is our opinion that Requirements R3 and R4 should be modified to include an exception for an IBR that is in-service by the effective date of PRC-029-1 and has a known hardware limitation that prevents the IBR from meeting Frequency Ride-through criteria.

R4. Lastly, it is ACES opinion that the acronym “CEA” should be spelled out in the first use within PRC-029-1 so as to eliminate any confusion as to what this term means. “CEA” is not a defined term and while it used in the NERC Rules of Procedure, it is not commonly used within the Reliability Standards.

Likes 0	
Dislikes 0	
Response	

George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	

Pattern Energy supports Edison Electric Institute’s and Grid Strategies LLC’s comments.

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	

Comment

PGAE recommends R3 and R4 to be revised to allow for existing IBR facility limitations for Frequenecy Ride Through, similar to the approach in R1 and R2.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators

Answer	No
Document Name	

Comment

It is the opinion of ACES that the definition of what constitutes an IBR should be consistent across the industry. The Project 2020-06 SDT has been working diligently towards this goal and we do not believe that an individual standard should deviate from their approach. Thus we recommend removing the phrase “The Elements associated with” from section 4.2 and modifying this section as follows:

4.2. Facilities:

4.2.1. Bulk Electric System (BES) IBRs; and

4.2.2. Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

R1. ACES believes that phrase “and is initiated by a non-fault switching event on the transmission system” should be struck from the 3rd bullet point of Requirement R1. It is our opinion that the GO will likely be unable to differentiate between an event initiated by a fault or an event initiated by a “non-fault switching event” on the Transmission system. In short, Transmission switching events are outside the purview of the GO.

R3/R4. ACES has grave concerns with the lack of any exceptions to Requirement R3 for existing IBRs. It is our opinion that Requirements R3 and R4 should be modified to include an exception for an IBR that is in-service by the effective date of PRC-029-1 and has a known hardware limitation that prevents the IBR from meeting Frequency Ride-through criteria.

R4. Lastly, it is ACES opinion that the acronym “CEA” should be spelled out in the first use within PRC-029-1 so as to eliminate any confusion as to what this term means. “CEA” is not a defined term and while it used in the NERC Rules of Procedure, it is not commonly used within the Reliability Standards.

Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	

Invenergy has the following comments regarding this draft of PRC-029-1:

R1: Bullet 3 presents significant challenges, and it is unclear how an entity would demonstrate compliance with the design aspect of PRC-029-1. Generator Owners will likely not be able to properly model the non-fault switching event condition and would thus be unable to independently assure design adherence to that requirement.

Remove “in whole or part” from Footnote 7 and Footnote 10. As drafted, the footnotes are inconsistent with IEEE-2800.

Attachment 1 bullet 10 must be removed or significantly amended. Some protection decisions must be made in a matter of micro-seconds, and as drafted, bullet 10 would adversely impact reliability by subjecting equipment to potentially damaging surges of current or voltage that near instantaneous protection settings are designed to mitigate.

Invenergy disagrees with the SDT’s interpretation of FERC Order 901, and we would like to reiterate that there is no clear evidentiary record to support the exclusion of limited exceptions from the frequency ride-through requirements. What’s most concerning however is the SDT’s recent assertion that it “does not have sufficient data at this time to determine whether additional frequency-based exemptions are appropriate and consistent with the overall reliability goals of Order No. 901.” We continue to await the requested technical justification studies and would like to direct the SDT to the several public comments filed by OEMs in ERCOT’s NOGRR 245 proceeding, that illustrate equipment challenges to meet reasonable data driven ride-through capability limits that fall below the current draft of PRC-029-1.

- **GE**

245NOGRR-58 GE Vernova Comments 110723.doc (live.com)

245NOGRR-63 GE Vernova Comments 011924.docx (live.com)

- **Vestas**

245NOGRR-57 Vestas Comments 110123.doc (live.com)

- **Siemens Gamesa**

245NOGRR-56 Siemens Gamesa Renewable Energy Comments 103023.docx (live.com)

Additionally, the SDT and NERC are encouraged to leverage the industry provided information regarding equipment limitations submitted according to provisions in the currently effectively Reliability Standard PRC-024-3.

As written, Draft 3 of PRC-029-1 ignores the technical realities surrounding many gigawatts of inverter-based resources installed on the BES today and **provides no path to compliance** for entities with well documented and understood hardware limitations. Invenergy would like to remind NERC that FERC has on many occasions, including within Order 901, granted NERC the leeway to exercise its technical expertise, experience, and discretion to develop appropriate requirements.

A reasonable path to compliance for facilities with equipment that is unable to meet the proposed voltage or frequency ride-through requirements would be to retain and carry over R3 from PRC-024-4. This would ensure equitable treatment of all generation types, provide sensible accommodations for equipment limitations, and push facilities to maximize their capabilities to the extent possible. In fact, FERC alluded to that in paragraph 193 of Order 901, stating, “We encourage NERC’s standard drafting team to consider currently effective Reliability Standard PRC-024-3, Requirement R3 as an example for establishing registered IBR technology exemptions.”

Absent limited exemptions from the ride-through requirements or a clear path to compliance for entities with hardware limitations, the frequency bands must be amended. To date, the SDT has provided no evidence that the proposed frequency bands, well beyond those of IEEE-2800-2002, would benefit BES reliability.

Likes 0	
Dislikes 0	

Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	

Invenergy has the following comments regarding this draft of PRC-029-1:

R1: Bullet 3 presents significant challenges, and it is unclear how an entity would demonstrate compliance with the design aspect of PRC-029-1. Generator Owners will likely not be able to properly model the non-fault switching event condition and would thus be unable to independently assure design adherence to that requirement.

Remove “in whole or part” from Footnote 7 and Footnote 10. As drafted, the footnotes are inconsistent with IEEE-2800.

Attachment 1 bullet 10 must be removed or significantly amended. Some protection decisions must be made in a matter of micro-seconds, and as drafted, bullet 10 would adversely impact reliability by subjecting equipment to potentially damaging surges of current or voltage that near instantaneous protection settings are designed to mitigate.

Invenergy disagrees with the SDT’s interpretation of FERC Order 901, and we would like to reiterate that there is no clear evidentiary record to support the exclusion of limited exceptions from the frequency ride-through requirements. What’s most concerning however is the SDT’s recent assertion that it “does not have sufficient data at this time to determine whether additional frequency-based exemptions are appropriate and consistent with the overall reliability goals of Order No. 901.” We continue to await the requested technical justification studies and would like to direct the SDT to the several public comments filed by OEMs in ERCOT’s NOGRR 245 proceeding, that illustrate equipment challenges to meet reasonable data driven ride-through capability limits that fall below the current draft of PRC-029-1.

GE

245NOGRR-58 GE Vernova Comments 110723.doc (live.com)

245NOGRR-63 GE Vernova Comments 011924.docx (live.com)

Vestas

245NOGRR-57 Vestas Comments 110123.doc (live.com)

Siemens Gamesa

245NOGRR-56 Siemens Gamesa Renewable Energy Comments 103023.docx (live.com)

Additionally, the SDT and NERC are encouraged to leverage the industry provided information regarding equipment limitations submitted according to provisions in the currently effectively Reliability Standard PRC-024-3.

As written, Draft 3 of PRC-029-1 ignores the technical realities surrounding many gigawatts of inverter-based resources installed on the BES today and **provides no path to compliance** for entities with well documented and understood hardware limitations. Invenergy would like to remind NERC that FERC has on many occasions, including within Order 901, granted NERC the leeway to exercise its technical expertise, experience, and discretion to develop appropriate requirements.

A reasonable path to compliance for facilities with equipment that is unable to meet the proposed voltage or frequency ride-through requirements would be to retain and carry over R3 from PRC-024-4. This would ensure equitable treatment of all generation types, provide sensible accommodations for equipment limitations, and push facilities to maximize their capabilities to the extent possible. In fact, FERC alluded to that in paragraph 193 of Order 901, stating, “We encourage NERC’s standard drafting team to consider currently effective Reliability Standard PRC-024-3, Requirement R3 as an example for establishing registered IBR technology exemptions.”

Absent limited exemptions from the ride-through requirements or a clear path to compliance for entities with hardware limitations, the frequency bands must be amended. To date, the SDT has provided no evidence that the proposed frequency bands, well beyond those of IEEE-2800-2002, would benefit BES reliability.

Likes 0	
Dislikes 0	

Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
We concur with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
NIPSCO recommends removing the phrase “demonstrate the design of each facility” from the proposed standard and returning to the original event-based requirements. The phrase may prove difficult to fully comply with, as a Functional Entity would have to know the design of the collector system and parameters and run the models correctly to demonstrate this. Much of this needed information would need to be provided by the manufacturer, which may require non-disclosure agreements. Please clarify or remove “other mechanisms” from requirement R2.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	

Requirement 2.1.1 through 2.1.3 are all required, recommend ensuring consistency in formatting and include an “and” at the end of 2.1.2.

Request clarification of the intent of 2.1.3. The proposed language is not written clearly, and the intent is not apparent. Recommend at a minimum addressing this sub-requirement in the technical rationale. An additional recommendation is to provide clarification on how requirement 2.1.3 relates to the tables in Attachment 1.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

R3. Wording “…and the absolute rate of change of frequency (RoCoF)12 magnitude is less than or equal to 5 Hz/second.” should be removed from R3. The rate of change of frequency nas never been an issue in past IBR disturbances. In addition, PRC-024 does not mentions and includes rate of change of frequency requirements. There is no technical rationale for this.

R3. Requirement should include exceptions due to hardware limitation, the same exception that was given for voltage requirements. WEC Energy Group owns a wind farm with frequency limitation that may not meet PRC-029 requirements. Please explain what should we do? Do not overlook limited capabilities of older Type 3 wind IBRs. WEC Energy Group recognized similar concerns commented by industry, please address it.

WEC Energy Group suggests SDT to create and add graphs for support Tables 1 and 2 and the respective notes. Graphs should highlight “must Ride□through zone” and “may Ride□through zone” terms that are listed in note 11.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	No
Document Name	

Comment

"Please see EEI Comments"

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	2020-02 LG&E KU Comments.docx
Comment	

Please see the attached comments.

Likes 0	
Dislikes 0	
Response	

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI does not support the approval of PRC-029-1 because it intends to require existing resources to meet the frequency performance standards mandated in Requirement R3 and provides no mechanism for IBR resource owners to declare a technical exemption consistent with voltage ride-through requirements contained in Requirements R1 and R2. It is EEI's understanding that this was done because the drafting team (DT) understood that the FERC Order did not allow any exemption for frequency ride-through requirements. However, in Paragraph 193 of FERC Order No. 901, the Commission expressly directed NERC to determine through its standards development process whether the Reliability Standards mandated therein should include a limited exemption for certain IBRs from voltage ride-through performance requirements. Importantly, the Commission, in Order No. 901 did not concomitantly prohibit the inclusion of a similar exemption from frequency ride-through performance requirements, either expressly or implicitly. Rather, it left that decision firmly in the hands of subject matter experts, as was made evident when it encouraged "NERC's standard drafting team to consider currently effective Reliability Standard PRC-024-3, Requirement R3 **as an example for establishing registered IBR technology exemptions**." *Reliability Standards to Address Inverter-Based Resources*, Order No. 901, 185 FERC ¶ 61,042, at P 193 (2022) (emphasis added).

EEI further notes that we are unaware of any frequency ride-through events, beyond equipment control setting errors, that have been documented and cited in any of the NERC Event reports to justify a need to disallow reasonable equipment exemptions for IBRs that cannot meet the proposed frequency ride-through requirements. Nevertheless, PRC-029-1 contains requirements for frequency ride-through that are likely infeasible to implement through either hardware or software means, in many cases for existing resources. (Noting that while software upgrades might be a viable option for some newer IBRs, software solutions for older resources would not be a viable remedy because many of the older resources would not have the computing capability necessary to support such upgrades.)

To address our concerns, we recommend the following:

1. Change PRC-029-1 to include reasonable and justified exemptions for legacy IBR facilities. (*See edits to R4 below*)
2. Align the Frequency ride-through curve in PRC-029-1 with IEEE 2800-2022. (*Align Table 3 of attachment 2 to IEEE 2800-2022*)

PRC-029-1 (Requirement R4 – Changes in Boldface)

R4. Each Generator Owner identifying an IBR that is in-service by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting voltage **and frequency** Ride-through criteria as detailed in Requirements R1**,** R2, **and R3** and requires an exemption from specific Ride-through criteria shall*:10 Lower] [Time Horizon: Long-term Planning]*

4.1. Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1. This documentation shall include:

4.1.1 Identifying information of the IBR (name and facility #);

4.1.2 Which aspects of voltage **or frequency** Ride-through requirements that the IBR would be unable to meet and the capability of the hardware due to the limitation;

4.1.3 Identify the specific piece(s) of hardware causing the limitation;

4.1.4 Supporting technical documentation verifying the limitation is due to hardware that needs to be physically replaced or that the limitation cannot be removed by software updates or setting changes, and;

4.1.5 Information regarding any plans to remedy the hardware limitation (such as an estimated date).

4.2. Provide a copy of the information detailed in Requirement R4.1 to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA no later than 12 months following the effective date of PRC-029-1.

4.2.1 Any response to additional information requested by the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA shall be provided back to the requestor within 90 days of the request.

4.2.2 Provide a copy of the acceptance of **a** hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s).11

4.3. Each Generator Owner with a previously accepted limitation that replace the hardware causing the limitation shall document and communicate such a hardware change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the hardware change.

4.3.1 When existing hardware causing the limitation is replaced, the exemption for that Ride-through criteria no longer applies.

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

See EEI Comments

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment	
Constellation aligns with NAGF comments. Kimberly Turco on behalf of Constellation Energy Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	

Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	

Facilities:

4.2.1. The Elements associated with (1) Bulk Electric System (BES) IBRs inverter□based resources and (2) Non□BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV

NextEra aligns with EEI's recommendation to remove "elements associated with" from Section 4.2.1

R1 and R2

NextEra believes that further clarity on reporting could be added to R1 and R2 consistent with the technical rationale.

R3

With a large portion of wind fleet across multiple OEMS, NextEra recommends there be an exception process for R3, or that it should not be applied retroactively. This is a particular concern for entrants for the Non-BES Assets.

R4

NextEra aligns with the below comments provided from EEI:

EEI does not agree with imposing new unverified requirements on existing resources as proposed in PRC-029-1 because it is unclear how many existing resources can meet the frequency performance standards mandated in Requirement 3. We are additionally concerned because resource owners have not been given adequate time to fully assess the impact of imposing these new requirements on their existing resources, which align with IEEE 2800-2022 (See 7.3.2.1 Figure 12 & Table 15 (Frequency ride-through, page 80; and see 7.3.2.3.5 Rate of change of frequency (ROCOF), page 82), and did not exist as a Standard until February 2022, after most of these resources were built or placed in service. For this reason, we cannot support the approval of PRC-029-1 without the following changes to Requirement 4 ensure that existing resources that were not design and do not have the capability to meet these requirements are allowed to declare an exemption for frequency ride-through similar to what is provided for resources that cannot meet the voltage ride-through requirements. See the proposed changes to R4 in boldface below:

R4. Each Generator Owner identifying an IBR that is in-service by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting voltage **and frequency** Ride-through criteria as detailed in Requirements R1**, and** R2, **and R3** and requires an exemption from specific **voltage** Ride-through criteria shall:*10 Lower] [Time Horizon: Long-term Planning]*

4.1. Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1. This documentation shall include:

4.1.1 Identifying information of the IBR (name and facility #);

4.1.2 Which aspects of voltage **or frequency** Ride-through requirements that the IBR would be unable to meet and the capability of the hardware due to the limitation;

{C}**4.1.3** Identify the specific piece(s) of hardware causing the limitation;

4.1.4 Supporting technical documentation verifying the limitation is due to hardware that needs to be physically replaced or that the limitation cannot be removed by software updates or setting changes, and;

4.1.5 Information regarding any plans to remedy the hardware limitation (such as an estimated date).

4.2. Provide a copy of the information detailed in Requirement R4.1 to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA no later than 12 months following the effective date of PRC-029-1.

4.2.1 Any response to additional information requested by the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA shall be provided back to the requestor within 90 days of the request.

4.2.2 Provide a copy of the acceptance of **an a** hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner (s), Transmission Operator(s), and Reliability Coordinator(s).11

4**.3.** Each Generator Owner with a previously accepted limitation that replace the hardware causing the limitation shall document and communicate such a hardware change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the hardware change.

4.3.1 When existing hardware causing the limitation is replaced, the exemption for that Ride-through criteria no longer applies.

Footnote 7

“Available Real Power” is not NERC defined term located in the NERC Glossary of Terms. By adding to the footnote, this creates confusion.

NextEra recommends defining and adding to NERC Glossary.

Likes 0	
Dislikes 0	
Response	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	

Capital Power supports the NAGF's comments:

The NAGF strongly recommends that PRC-029 be revised to allow for frequency ride through (“FRT”) exemptions to address such limitations for legacy IBR facilities. Not including FRT exemptions will result in a standard that will make certain IBR legacy facilities automatically non-compliant when the standards become effective.

Requirement R3 – the NAGF is concerned that legacy IBR facilities are not capable of meeting the 5 Hz/second maximum ROCOF or the 25-degree phase angle jump requirements. Therefore, FRT exemptions are necessary and need to be included in Requirement R3. In support of this concern, the NAGF points to the ERCOT NOGRR245 TAC Presentation, December 4, 2023 – page 4 which indicates that 40% of OEMs cannot comply with the previously proposed specific 5 Hz/second maximum ROCOF requirement and 41% of OEMs cannot comply with the previously proposed specific 25-degree phase angle jump requirement.

December 4 2024 NOGRR245 TAC Stephen Solis - Principal System Operations Improvement

Requirement R4.2.2 – the NAGF is unclear as to what the Compliance Enforcement Authority (CEA) acceptance for an IBR hardware limitation exemption will consist of. Will the CEA provide an email response confirming acceptance to the Generator Owner submitting the exemption? How are such exemptions to be submitted and to whom within the CEA organization?

In addition to the NAGF comments above, after discussions with a wind turbine OEM, some legacy equipment will not be able to handle the 64 Hz overfrequency ride-through requirement stipulated in PRC-029. Requiring IBRs to ride through an overfrequency in the range of 61.8 Hz to 64 Hz is beyond the IEEE 2800 standard, as stated by the SDT within the technical rationale. We recommend aligning the frequency ride-through requirement to be more in line with the IEEE 2800 standard and reducing the final "no-trip" overfrequency requirement to 61.8Hz in addition to changing the wording of Requirement R4 to allow for FRT exemptions. More discussions with IBR OEMs must be held to confirm equipment capabilities.

Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	

Constellation aligns with NAGF comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	

Comment	
The NAGF strongly recommends that PRC-029 be revised to allow for frequency ride through ("FRT") exemptions to address such limitations for legacy IBR facilities. Not including FRT exemptions will result in a standard that will make certain IBR legacy facilities automatically non-compliant when the standards become effective. *Requirement R3 – the NAGF is concerned that legacy IBR facilities are not capable of meeting the 5 Hz/second maximum ROCOF or the 25-degree phase angle jump requirements. Therefore, FRT exemptions are necessary and need to be included in Requirement R3. In support of this concern, the NAGF points to the ERCOT NOGRR245 TAC Presentation, December 4, 2023 – page 4 which indicates that 40% of OEMs cannot comply with the previously proposed specific 5 Hz/second maximum ROCOF requirement and 41% of OEMs cannot comply with the previously proposed specific 25-degree phase angle jump requirement.* *December 4 2024 NOGRR245 TAC Stephen Solis - Principal System Operations Improvement* *The NAGF recommends aligning exception language with IEEE-2800. The proposed PRC-029 ride through requirements do not include the technology limitations discussed in IEEE-2800.* *Requirement R4.2.2 – the NAGF is unclear as to what the Compliance Enforcement Authority (CEA) acceptance for an IBR hardware limitation exemption will consist of. Will the CEA provide an email response confirming acceptance to the Generator Owner submitting the exemption? How are such exemptions to be submitted and to whom within the CEA organization?*	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
• AES CE believes additional changes are needed as explained below.	
Likes 0	
Dislikes 0	
Response	
Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	No
Document Name	
Comment	
TransAlta supports multiple other organizations who recommend the addition of frequency ride-through to the allowable hardware limitations in R4.	
Likes 0	

Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 2

Likes 0	
Dislikes 0	

Response

Michael Goggin - Grid Strategies LLC - 5

Answer	No
Document Name	

Comment

In the current draft of PRC-029, R4 should be modified to allow existing resources with equipment limitations to obtain an exemption from the frequency ride-through requirements in R3, instead of only allowing an exemption from the voltage ride-through requirements in R1 and R2. This is necessary because most existing IBR generators cannot meet the stringent frequency ride-through requirements proposed in R3 without deploying significant hardware modifications or replacement, which goes against the intent of FERC Order 901.

Without change, a large share of the 270 GW of operating IBR plants,[1] representing an investment of hundreds of billions of dollars, will be forced into early retirement. Abruptly forcing such a large volume of existing generators offline would not only impose massive costs, but also cause generation shortfalls in many regions. Such drastic action could be understandable if the frequency ride-through requirement were addressing a real reliability concern. However, NERC and the drafting team have repeatedly been unable to provide any technical justification for imposing the frequency ride-through requirement existing IBR plants. None of the reports NERC has published in response to IBR ride-through events have identified frequency ride-through as a significant concern. There is no reason to impose such a massive cost and reliability impact for a solution in search of a problem.

Information provided by the two largest IBR owners in the U.S. confirms that most existing IBRs cannot meet the frequency ride-through requirements. One of these developers indicated that more than 30% of its fleet could not comply with the draft standard. The other indicated that half of its operating IBR fleet has no viable path to compliance, and a large share of the remainder will require cost-prohibitive retrofits, so if the standard went into effect as drafted a large share of its operating fleet will have to be retired or fully repowered. Other developers that operate the remainder of the 270 GW IBR fleet would likely see comparable impacts. Retiring, or at best taking out of service for an extended period of time for repowering, such a large volume of facilities during a time of rapid growth in peak load and energy needs would cause far greater reliability concerns than whatever concern the frequency ride-through requirement is attempting to address.

Information provided by these developers indicates that a large share of wind, solar, and battery resources cannot meet the frequency ride-through standard without significant hardware replacement. The frequency ride-through requirements are particularly problematic for some existing wind generators. In the Technical Rationale document accompanying the second PRC-029 draft, the drafting team notes that some wind generators are more sensitive to frequency deviations, writing that “All IBR resources (except for type 3 wind turbines) interface to the grid through fast switching of power electronics devices. These power electronic devices are much less sensitive to the transmission system frequency excursion than non□hydraulic turbine synchronous resources."[2] However, the drafting team then incorrectly concludes that "Therefore, IBR should be capable of riding through the increased proposed 6second frequency ridethrough requirement without risk of equipment damage or need for frequency protection to operate." The Technical Rationale document does not offer any justification for its assumption that Type III wind turbines can meet the frequency ride-through requirements, despite noting that those turbines more directly interface with the grid and thus are more affected by frequency deviations than other IBRs.

In fact, many existing Type III wind turbines cannot meet the frequency ride-through requirements proposed in this draft of PRC-029. Those resources were designed to meet the reliability Standards and interconnection requirements that were in effect when they were placed in service, and were not designed to ride through frequency excursions of the magnitude and duration proposed in the draft Standard. Imposing a retroactive requirement on these generators is particularly problematic as it is not typically feasible to retrofit existing wind turbines to increase their ability to withstand mechanical stresses due to frequency changes. In such cases, making existing equipment better able to withstand frequency changes would require full replacement or extensive modification of hardware, which would come at a significant, and sometimes prohibitive, cost. At minimum, bringing wind plants that cannot meet the current standard into compliance would require replacing the turbine converter and controller. Further, frequency changes can impose mechanical stresses on highly sensitive elements in the wind turbine's rotating equipment, including the generator, gearbox, the main shaft, and bearings associated with all of that equipment, and requiring such resources to ride through frequency changes they were not designed to operate through can damage that equipment. Subjecting Type III wind turbines to this damage may lead to increased outages or premature failure of these generators, potentially increasing reliability risks. As noted above, if the standard went into effect as drafted a large share of the operating IBR fleet will have to be retired or fully repowered. Retiring these facilities during a time of rapid growth in peak load and energy needs would cause far greater reliability concerns than whatever concern the frequency ride-through requirement is attempting to address.

The Solution: Frequency ride-through exemptions for existing IBRs

The easiest solution is to modify R4 to allow existing resources with equipment limitations to obtain an exemption from the frequency ride-through requirements in R3, which would make PRC-029 consistent with a long precedent of FERC interconnection requirements and NERC Standards only applying prospectively, including PRC-024. Retroactive requirements impose a much greater financial burden on the generator than prospective Standards, and set a bad precedent by unfairly penalizing generators that met all requirements that were in effect at the time they were installed. Retrofit or replacement costs are typically much greater than if the capability were installed at the plant to begin with. In some cases parts needed for retrofits may not be available, particularly for models that have been discontinued or manufacturers that are no longer in business, potentially requiring the replacement of the entire power conversion system. Moreover, existing IBR generators typically sell their output at a fixed price under a long-term power purchase agreement, and unexpected retrofit or replacement costs cannot typically be recovered once a power purchase agreement has been signed. These unexpected and unrecoverable costs are far more concerning to lenders and other generation project financiers as they were not accounted for during the project's financing. As a result, retroactive requirements set a bad precedent by introducing regulatory uncertainty that makes future generation investment more uncertain and riskier, and likely more costly by forcing financiers to charge higher risk premiums. Changing the rules in the middle of the game and penalizing resources that were designed to the standards in effect at the time they were built also establishes a bad precedent, in addition to imposing costs that are not just and reasonable and undue discrimination relative to resources covered by PRC-024.

Fortunately, these problems can be fixed by simply inserting "R3" into the list of permissible exemptions in R4, which would allow existing resources with equipment limitations to obtain an exemption from the frequency ride-through requirements in R3.

In the Technical Rationale document, the drafting team points to FERC's directive in Order No. 901 to justify not allowing existing resources to obtain an exemption from the frequency ride-through requirements in R3: "FERC Order No. 901 states that this provision would be limited to exempting 'certain registered IBRs from voltage ridethrough performance requirements.' This is the reason that no similar provisions are included for exemptions for frequency or rateofchangeoffrequency (ROCOF) ridethrough requirements per R3."[3]

However, a contextual reading of Order No. 901 indicates FERC was focused on targeting equipment limitation exemptions at existing generators that would have to physically replace or modify hardware to comply with the Standard, and not focused on limiting such exemptions to voltage ride-through requirements. Paragraph 193 in its entirety, and particularly the first sentence, explain that FERC's intent was exempting existing resources that would have to physically replace or modify hardware: "we agree that a subset of existing registered IBRs –typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements directed herein." As a result, FERC continued by directing that "Any such exemption should be only for voltage ride-through performance for those existing IBRs that are **unable to modify their coordinated protection and control settings to meet the requirements without physical modification of the IBRs' equipment**."[4]

Allowing existing plants to apply for an equipment limitation exemption for the frequency ride-through requirements in R3 is necessary to ensure some existing generators do not have to physically replace or modify hardware, as explained above. As a result, such an exemption is consistent with FERC's directive and intent in Order No. 901. As documented in the following footnote, there is ample precedent for NERC and standards drafting teams to exercise their technical expertise to craft Standards to align content and requirements with technical realities.[5]

Additional context in Order 901 further demonstrates that FERC intended for NERC to include an exemption for existing IBRs that cannot meet frequency ride-through requirements. At paragraph 190 in Order No. 901, FERC directed NERC to develop Standards that ensure resources "ride through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults." For many existing IBRs that cannot meet the proposed frequency ride-through requirements, tripping is necessary to protect the IBR equipment, similar to when synchronous generation resources use tripping as protection from internal faults. As a result, an exemption from R3 for existing resources is consistent with FERC's intent. Order No. 901 also directed NERC to consider the "PRC-024-3, Requirement R3 as an example for establishing registered IBR technology exemptions," and that exemption applies equally to voltage ride-through and frequency ride-through settings, further suggesting that FERC will allow certain IBRs an exemption from the frequency ride-through requirements.[6] Finally, Order No. 901 notes that in the notice of proposed rulemaking that led to the order, FERC "proposed to direct NERC to develop new or modified Reliability Standards that would require registered IBR facilities to ride through system frequency and voltage disturbances where technologically feasible."[7] FERC then adopted that very proposal,{C}[8] further demonstrating that FERC sought to direct NERC to only require frequency and voltage ride-through where technologically feasible.

When asked about this issue, FERC staff has indicated that as a general matter, when a Commission Order is silent on a topic it is neither requiring something nor requiring the absence of that thing. NERC is taking a contrary position by arguing that due to FERC's silence they are not allowed to give an exemption for frequency ride-through.

NERC has been unable to present any technical reason why FERC would not allow a frequency ride-through exemption for existing IBRs, as none exists. Frequency ride-through has not been identified as a significant concern in any of the reports NERC has commissioned regarding IBR ride-through during disturbance events. Moreover, there is no technical justification for requiring existing IBRs to meet the extremely wide frequency ride-through bands proposed in PRC-029. PRC-029 requires IBRs to remain online for 6 seconds at 56-64 Hz, 5 minutes at 57-61.8, 11 minutes at 58.5-61.5, and indefinitely at 58.8-61.2 Hz. Under-Frequency Load Shedding (UFLS) that restores frequency following an extreme disturbance typically begins at 59.4 or 59.5 Hz. There is no credible reliability reason for requiring IBRs to remain online for 5 minutes for excursions that are 5 times more severe than the threshold at which UFLS restores frequency, and indefinitely for a frequency excursion twice as severe as that threshold. Such a requirement for IBRs is particularly pointless because PRC-024 would have allowed synchronous resources' relays to trip those generators far before that point for far less severe excursions.

This highlights another likely reason FERC Order No. 901 did not explicitly direct NERC to include frequency ride-through exemptions: FERC did not anticipate that NERC would adopt such a strict frequency ride-through requirement that some existing IBR plants cannot meet it. The drafting team even notes at page 7 in the Technical Rationale document that "The proposed 6□second time frame of the frequency ride□through capability requirement is beyond the IEEE 2800 standard frequency ride□through requirement and beyond frequency ride□through requirements for synchronous machines under proposed PRC□024□4." There is nothing in Order No. 901 that suggests that FERC was opposed to existing equipment exemptions for a frequency ride-through standard that was drafted after FERC issued Order No. 901 and is more stringent than FERC anticipated. A much more reasonable interpretation is that the logic FERC provided in paragraph 193 of Order No. 901 also applies to a frequency ride-through requirement that some existing resources cannot meet without physical modification or replacement of equipment. In fact, paragraph 193 makes clear that FERC's language focuses on an exemption from voltage ride-through requirements because "a subset of existing registered IBRs… may be unable to implement the voltage ride though performance requirements directed herein."

At the end of paragraph 193, FERC also explained that an exemption for existing resources would not harm reliability because "The concern that there are existing registered IBRs unable to meet voltage ride through requirements should diminish over time as legacy IBRs are replaced with or upgraded to newer IBR technology that does not require such accommodation." FERC's reasoning in paragraph 193 also applies to an exemption from frequency ride-through requirements, but particularly the conclusion that exempting existing plants does not cause reliability concerns and therefore should be allowed. The NERC drafting team's technical justification document explicitly explains that the frequency ride-through requirement is "to ensure the reliability of future grids with high IBR penetration,"{C}[9] based on concerns about declining inertia due to IBRs replacing synchronous resources. NERC and others have demonstrated that inertia and frequency response will remain more than adequate for the foreseeable future even following disturbances that are several times larger than current credible contingencies, and that higher IBR penetrations can actually significantly improve frequency stabilization following disturbances.[10]

As a result, there is no reliability concern from an exemption for the small number of existing resources that cannot meet the requirements without physical modification or replacement of equipment. Moreover, as FERC notes, these plants will replace that equipment anyway over time as legacy inverters fail or are replaced with more modern equipment for other reasons, and the draft standard requires replacement equipment to comply with the Standard. Utility-scale inverters installed at solar and battery installations typically come with warranties of 10 years or less,{C}[11] and those inverters are typically replaced at least once during the plant's lifetime. Many existing wind plants are also being repowered with newer turbines, often to allow the project to receive another 10 years of production tax credits after the initial 10 years of credits have been received. As a result, by the time the drafting team's concerns about inertia in a high IBR penetration future might materialize, the vast majority of IBRs that cannot meet the frequency ride-through requirements will have been replaced with new equipment that is not exempt.

Moreover, the drafting team's assumption that frequency deviations will be larger on a future low inertia power system is flawed. IBRs can provide fast frequency response, which stabilizes frequency in the initial seconds following a grid disturbance, before synchronous generators begin to provide their slower primary frequency response.[12] Thus fast frequency response provides a similar service to inertia in helping to arrest the change in frequency before primary frequency response is fully deployed, reducing the need for inertia.[13] Fast frequency response is easily provided by batteries due to their available energy, but can also be provided by curtailed wind or solar resources. Power systems with high IBR penetrations will tend to have some wind or solar curtailment in a significant share of hours. If allowed to do so, solar an battery resources with spare DC capacity behind the inverter can also temporarily exceed their interconnection agreement's AC injection limit to provide fast frequency response.

The replacement of inflexible synchronous resources with more flexible IBRs could also significantly improve primary frequency response, as NERC's modeling has demonstrated.{C}[14] NERC has also documented that only about 30% of synchronous generators provide primary frequency response, and only about 10% provide sustained primary frequency response.[15] Even with less inertia, the fast and accurate frequency response provided by IBRs will keep frequency more tightly controlled than the slow to nonexistent primary frequency response from synchronous generators. The replacement of large synchronous generators with smaller IBRs should also reduce the magnitude of frequency deviations following the loss of generators. If frequency response does begin to emerge as a concern, the more effective solution would be to enforce requirements on synchronous generators that are supposed to provide it but do not. If necessary, operators would alter real-time dispatch, as ERCOT and some island power systems occasionally do today, to ensure that inertia and fast frequency response are adequate to ensure under-frequency load shedding or generator tripping thresholds are not reached. Finally, grid-forming inverters are increasingly being deployed with battery storage and other IBR installations, further increasing the contributions of IBRs to stabilizing frequency.

At page 8 in the Technical Rationale document, the drafting team argues that "To compensate for the lack of inertia and short circuit contributions, [IBRs] should have wider tolerances for frequency and voltage excursions to meet the needs of future power systems with a higher percentage of IBR." The drafting team also argues that IBRs should have to ride-through much larger frequency deviations than synchronous resources because "Synchronous resources are more sensitive to frequency deviations than IBR resources." This logic is flawed for many reasons. Grid operators need all resources to ride through disturbances, and the contribution of a resource to inertia or short circuit needs is irrelevant to that need. Any concerns about resources' inertia and short circuit contributions are outside the drafting team's scope and authority, and should be addressed by other means (such as by increasing the deployment of grid-forming IBRs in the localized areas that have short circuit or stability concerns). It is also perverse for the drafting team to penalize IBRs for being less sensitive to frequency deviations than synchronous generators. As noted below, there are already grounds for FERC to reject this proposed standard due to undue discrimination against IBRs relative to the far more lenient requirements on synchronous generators under PRC-024, including an equipment limitation exemption for synchronous generators from the frequency relay setting requirement in PRC-024,[16] and this only adds to those concerns.

In short, the drafting team's unfounded concerns about a future power system do not justify withholding an exemption to frequency ride-through requirements for existing IBRs that will have been largely replaced by the time any concerns might materialize.

Finally, R4 equipment limitation exemptions should be allowed for resources with signed interconnection agreements as of the effective date of the Standard, instead of resources that are in-service as of that date. Resource equipment decisions are typically locked down at the time the interconnection agreement is signed, and a change in requirements after that point can require a costly change in equipment or settings that may also trigger a material modification and resulting interconnection restudies. The implementation plan for PRC-029 indicates that the effective date for the Standard will be the first day of the first quarter six months after FERC approval. Many resources take significantly longer than that to move from a signed interconnection agreement to being placed in service, so it makes more sense to allow R4 equipment limitation exemptions for resources that have a signed interconnection agreement as of the effective date of the Standard.

The current draft of the PRC-029 Standard is unworkable and will impose massive costs on some existing generators with no benefit for reliability. As explained above, the drafting team incorrectly ventures that "IBR should be capable of riding through the increased proposed 6second frequency ridethrough requirement without risk of equipment damage or need for frequency protection to operate," even after noting that some wind turbines use very different technology. NERC's rigorous standard development process exists to ensure that errors like this do not make it into final Standards, and the exceedingly low level of support for the initial draft and the major revisions in the current draft indicate that further revisions will likely be necessary. It takes time to fine tune highly technical requirements and vet them across the industry to avoid unnecessary and exorbitant costs for existing resources that cannot meet the standard.

If PRC-29 continues to fall short of the level of support required for approval in this round of balloting, and NERC proceeds under Rules of Procedure Rule 321.2.1 by having the Standards Committee convene a technical conference and use the input from the technical conference to revise the standard for a final re-balloting period, incorporating an exemption from the frequency ride-through requirement for existing IBR generators would help to secure sufficient support for the standard to pass during re-balloting. Irreparable and immediate harm will occur if PRC-029 is allowed to move forward in its current form, harm that cannot be undone even if NERC immediately opens a standards revisions effort after the adoption of PRC-029 to fix these concerns. The current implementation plan requires BES IBRs to “ensure the design of their IBR units meets the criteria” within 12 months following regulatory approval of the standard, while for non-BES IBRs the compliance deadline will be the later of January 1, 2027, or 12 months following regulatory approval of the standard.[17] A year or two provides IBR owners with no time to wait if hundreds of GW of existing IBRs are required to secure retrofit or replacement equipment, find skilled technicians and tools to install that equipment, and complete that work during scheduled plant outages, especially since the entire industry will be pulling from the same pool of equipment and skilled labor. As a result, if PRC-029 is approved in its current form, IBR owners will immediately begin incurring massive non-refundable costs for equipment orders and labor contracts, as they cannot wait in the hope that a subsequent revision effort will fix this error. Moreover, the typical timeline from Standard Authorization Request through standard balloting and FERC approval is much more than a year, so industry would have no reason to expect such an effort could be completed before PRC-029 took effect.

Alternative solutions

If NERC refuses to accept that Order 901 allows it to exempt existing IBRs from the frequency ride-through requirement, alternative solutions can mitigate the harm the proposed standard would cause. One alternative solution would be modifying the standard to allow IBRs, or at least existing IBRs, to meet far less stringent frequency ride-through curves than those proposed in PRC-029. The less stringent frequency ride-through curve or curves could be taken from PRC-024. As noted above, the PRC-024 curves are closer to but still significantly wider than UFLS thresholds, and thus are better tailored to meeting actual reliability needs. An additional advantage is that the PRC-024 curves have been in place for many years and thus many existing IBRs were designed with relays that would not trip them for disturbances of that magnitude. In contrast, the curves proposed in PRC-029 are far more stringent than past design practice and could not have been anticipated by IBRs when they were built. Industry could work to identify a reasonable and attainable frequency ride-through curve or curves at the technical conference that will likely be convened due to Rule 321.2.1, which could then be incorporated into the revised standard that subsequently goes out for a final re-balloting period.

This approach will not mitigate all of the harm caused by PRC-029, as PRC-024 still allows exemptions for equipment limitations,[18] while NERC is taking the position that PRC-029 cannot. Moreover, adopting something approximating the PRC-024 curves in PRC-029 would still result in disparate treatment for IBRs because PRC-024 is only a relay-setting standard and PRC-029 is a ride-through performance requirement. The most elegant solution, and the one least likely to result in a costly mistake that requires expensive retrofits and plant retirement for no reliability benefit, and risk FERC rejection of the standard, is to simply include an exemption for existing resources.

Undue discrimination

Providing an exemption in PRC-029 R4 for existing IBRs that cannot meet the frequency ride-through requirement in R3 will provide less disparity with the treatment of synchronous resources under PRC-024, and is therefore an essential step if NERC wants to reduce the risk of FERC rejecting the proposed standard due to undue discrimination against IBRs. As noted above, PRC-024 allows exemptions for equipment limitations,[19] so exempting existing IBRs from PRC-029’s frequency ride-through requirements would reduce the undue discrimination towards IBRs.

It should also be noted that PRC-029 is far more stringent because it is a ride-through performance requirement, while the existing and proposed versions of PRC-024 are simply relay-setting standards. PRC-024 only requires protective relays to be set so they do not trip the generator within specified bounds, but it allows a resource to trip offline for other reasons. PRC-024-4 explicitly allows a plant to trip if protection systems trip auxiliary plant equipment, per section 4.2.3. In contrast, PRC-029 is a performance standard that requires IBRs to remain electrically connected and to continue to exchange current within the specified voltage and frequency bounds. Said another way, an IBR and a synchronous resource could both trip during the same disturbance, and the IBR would be in violation of PRC-029 but the synchronous generator would not be in violation of PRC-024-4, as long as the synchronous generator did not trip due to the settings of its protection system.

To ensure grid reliability and resilience, all resources including IBRs and synchronous resources should ride through grid disturbances. The failure of synchronous generators to ride through grid disturbances threatens grid reliability as much or more than the failure of IBRs, as synchronous resources are often producing at a higher level of output, are more typically relied on as capacity resources, and often take longer to come back online and ramp up to full output if they trip due to a disturbance.

FERC Order No. 901 directed NERC to treat IBRs similarly to how NERC Standards treat synchronous generators, writing that the IBR Standard should "permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults."{C}[20] Allowing synchronous generators to trip but requiring IBRs to ride through the same or similar disturbance could be challenged at FERC as undue discrimination. Providing synchronous generators with an exemption from PRC-024's frequency relay setting requirements but not offering IBRs an exemption from the far more stringent frequency ride-through requirements in PRC-029 only compounds the undue discrimination, and makes an even stronger case for FERC to reject PRC-029 as proposed.

Not requiring ride-through performance from synchronous generators is also at odds with the intent for this project that NERC stated in its February 2023 comments on the FERC proposed rulemaking that led to Order No. 901: "A comprehensive, performance-based ride-through standard is needed to assure future grid reliability. To that end, NERC re-scoped an existing project, Project 2020-02 Modifications to PRC-024 (Generator Ride-through), to revise or replace current Reliability Standard PRC-024- 3 with a standard that will require ride-through performance from all generating resources."[21] FERC's Order No. 901 also noted NERC's statement that this project would require ride-through performance from all generating resources,[22] so a failure to require ride-through performance from synchronous generators is contrary to both NERC's and FERC's intent.

Providing an exemption in PRC-029 R4 for existing IBRs that cannot meet the frequency ride-through requirement in R3 will provide less disparity with the treatment of synchronous resources under PRC-024, and is therefore an essential step if NERC wants to reduce the risk of FERC rejecting the proposed standard due to undue discrimination against IBRs.

{C}[1]{C} https://www.utilitydive.com/news/clean-energy-capacity-wind-solar-2024-acp-report/715501/

{C}[2]{C} Technical Rationale, PRC-029-1 – Frequency and Voltage Ride-Through Requirements for Inverter-Based Generating Resources, at 8, https://www.nerc.com/pa/Stand/202002_Transmissionconnected_Resources_DL/2020-02_PRC-029-1_Technical_Rationale_Redline_to_Last_Posted_06182024.pdf ("Technical Rationale").

{C}[3]{C} *Id.*, at 10

{C}[4]{C} *Reliability Standards to Address Inverter-Based Resources*, Order No. 901, 185 FERC ¶ 61,042, P 193 (2023).

{C}[5]{C} For example, **Section 215(d)(2) of the FPA** requires FERC to give "due weight" to the technical expertise of the ERO when evaluating the content of a proposed Reliability Standard or modification to a Standard.

Order No. 733-A, P 11: "In this order, we emphasize and affirm that we do not intend to prohibit NERC from exercising its technical expertise to develop a solution to an identified reliability concern that is equally effective and efficient as the one proposed in Order No. 733."

Order No. 748, P 43: "In consideration of these ongoing efforts, we will not direct specific modifications to these Reliability Standards and, rather, accept NERC's commitment to exercise its technical expertise to study these issues and develop appropriate revisions to applicable Standards as may be necessary."

Order No. 896, P 36: "NERC may also consider other approaches that achieve the objectives outlined in this final rule. Further, as recommended by PJM, we believe there is value in engaging with national labs, RTOs, NOAA, and other agencies and organizations in developing benchmark events. Considering NERC's key role, technical expertise, and experience assessing the reliability impacts of various events and conditions, we encourage NERC to engage with national labs, RTOs, NOAA, and other agencies and organizations as needed."

Order No. 901, P 192: "We believe that, through its standard development process, NERC is best positioned, with input from stakeholders to determine specific IBRs performance requirements during ride through conditions, such as type (e.g., real current and/or reactive current) and magnitude of current. NERC should use its discretion to determine the appropriate technical requirements needed to ensure frequency and voltage ride through by registered IBRs during its standards development process."

{C}[6]{C} Order 901, P 193

{C}[7]{C} *Id.* at P 178.

{C}[8]{C} *Id.* at P 190.

{C}[9]{C} Technical Rationale at 7.

{C}[10]{C} East Interconnection Frequency Response Assessment with Inverter Based Resources, at 7 https://www.energy.gov/sites/prod/files/2018/07/f53/2.1.4%20Frequency%20Response%20Panel%20-%20Velummylum%2C%20NERC.pdf.

{C}[11]{C} Best Practices for Operation and Maintenance of Photovoltaic and Energy Storage Systems, at 55, https://www.nrel.gov/docs/fy19osti/73822.pdf.

{C}[12]{C}Fast Frequency Response Concepts and Bulk Power System Reliability Needs, https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf.

{C}[13]{C} Inertia and the Power Grid: A Guide Without the Spin, https://www.nrel.gov/docs/fy20osti/73856.pdf.

{C}[14]{C} East Interconnection Frequency Response Assessment with Inverter Based Resources, at 7 https://www.energy.gov/sites/prod/files/2018/07/f53/2.1.4%20Frequency%20Response%20Panel%20-%20Velummylum%2C%20NERC.pdf.

{C}[15]{C} https://www.nerc.com/pa/Stand/Project%20200712%20Frequency%20Response%20DL/FRI_Report_10-30-12_Master_w-appendices.pdf

{C}[16]{C} https://www.nerc.com/pa/Stand/202002_Transmissionconnected_Resources_DL/2020-02_PRC-024-4_Draft_2_Clean_06182024.pdf, R3, at pages 5-6

{C}[17]{C} https://www.nerc.com/pa/Stand/202002_Transmissionconnected_Resources_DL/2020-02_PRC-024-4_PRC-029-1_Implementation%20Plan_Redline_to_Last_Posted_07222024.pdf

{C}[18]{C} https://www.nerc.com/pa/Stand/202002_Transmissionconnected_Resources_DL/2020-02_PRC-024-4_Draft_2_Clean_06182024.pdf, R3, at pages 5-6

{C}[19]{C} https://www.nerc.com/pa/Stand/202002_Transmissionconnected_Resources_DL/2020-02_PRC-024-4_Draft_2_Clean_06182024.pdf, R3, at pages 5-6

{C}[20]{C} Order No. 901, at P190

[21]{C}https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Comments_IBR%20Standards%20NOPR.pdf, at 21-22.

[22]{C} Order No. 901, at P185

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

1. Requirements R1, R2 and R3 use the phrase “ensure design and operation” to imply a Generator Owner is required to guarantee an IBR will be operated in Real-time as designed. We observe the Standard Drafting Team’s (SDT) previous response to the meaning of this phrase is clarified through the “additional specificity and examples for objectively evaluating compliance” within each requirement’s measure. We believe this is outside the scope of the NERC Protection and Control Reliability Standards, as only a Generator Operator can make such guarantees. The scope of the Protection and Control Reliability Standards are to ensure facility equipment is properly configured and with settings that achieved

sufficient and observable reliability during facility operating simulations. Several of these Reliability Standards have periodicities that ensure the initial design philosophy is still being achieved through repeatable simulations, even years after a facility's commissioning date. The purpose of NERC Reliability Standard PRC-005-6 is to ensure a facility's Protection Systems, particularly relays, are maintained within their intended design settings. We believe the phrase proposed by the SDT should be clarified to imply designed to operate under simulated conditions and disturbances. For Requirement R1, we propose this clarification for consideration, "Each Generator Owner shall ensure each IBR is designed, both initially and following the IBR's commissioning, to meet or exceed the Ride□through requirements in accordance with the Continuous Operation Region specified in Attachment 1."

2. We believe the possibility of an IBR limitation should not be limited to hardware. In the past, such limitations may have been imposed on Generator Owners because some equipment manufacturers were unable to achieve functional requirements through firmware modifications. Moreover, some equipment manufacturers terminated their business operations entirely. We believe the SDT should broaden each reference within the Reliability Standard and omit any descriptive adjectives associated with a limitation.
3. Part 2.1.3 states during a voltage excursion, each Generator Owner shall ensure the design of its IBR is set to prioritize Real Power or Reactive Power, unless overridden by another registered entity, when the voltage at the high side of the main power transformer is less than 0.95 per unit, yet still within the continuous operation region as specified in Attachment 1, and the IBR cannot deliver both Real Power and Reactive Power. We believe the SDT could simplify this language, as the Generator Owner will not have enough information of the Bulk Power System to make an informed decision on the appropriate priority during anticipated system conditions and configurations in the future. We believe the SDT should instead clarify the default priority for Generator Owners is Reactive Power, like Part 2.2.
4. Under Requirement R3, each Generator Owner is required to ensure its IBRs meet or exceed the Ride-through requirements during a frequency excursion event whereby the absolute rate of change of frequency (RoCoF) magnitude is less than or equal to 5 Hz/second. This requirement assumes the configurable function is enabled. We recommend the SDT clarify the absolute rate of change of frequency (RoCoF) magnitude requirement is set only when such a function is enabled.
5. To summarize Requirement R4, any limitations identifying an IBR is unable to meet the voltage Ride□through criteria detailed in Requirements R1 and R2 must be documented. Under the individual parts of this requirement, there is no option available for a Generator Owner to have a limitation indefinitely applied. We also believe Parts 4.1.4 and 4.1.5 require supporting technical documentation and plans to correct a limitation as possible language that should be incorporated in the requirement's measure.
6. We believe the SDT should modify the language of each measure for Requirements R1, R2, and R3. The phrase "but are not limited to" should be removed within each measure. The possible evidence identified should not imply that each example is needed. We also recommend replacing the "and" within the items of a series with an "or."
7. As defined within Section 2.5 of Appendix 3A (Standard Processes Manual) of the NERC Rules of Procedure, a Measure "provides identification of the evidence or types of evidence that may demonstrate compliance with the associated requirement." We believe the reference to "shall" within each measure of a requirement of this proposed Reliability Standard is misaligned with the NERC Rules of Procedure. For instance, as proposed, each Generator Owner is required to retain evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate the operation of each IBR did adhere to Ride□through requirements. Such data may not be available because of equipment failures that are then handled through compliance with other Reliability Standards. Entities also need to implement their own internal processes to extract this data before a limited storage capacity overrides this historical information. We believe the Standard Drafting Team should instead focus on identifying evidence that may demonstrate compliance, such as an ongoing design philosophy that each IBR will meet the Ride□through requirements in accordance with the Continuous Operation Regions specified within the Reliability Standard's attachments.
8. We believe a significant burden has been placed on Generator Owners with the expectation listed within Measure M2 that the Generator Owner will retain, for each voltage excursion, actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate that the operation of each IBR did adhere to this Reliability Standard's performance requirements. It should be noted that other proposed Reliability Standards are placing limitations on which voltage excursions are applicable for analysis. A similar burden is listed within Measure M3 with each frequency excursion. We recommend the SDT remove this burden entirely. Instead, we propose offering a Generator Owner an opportunity to provide their IBR's equipment settings for the period prior to the facility's commissioning and actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data at the Generator Owner's discretion. If the Generator Owner needs to demonstrate their facility's performance following a Disturbance, the actual disturbance monitoring data will be requested under Reliability Standard PRC-030-1. Moreover, such a request should originate from an external reliability entity and not require the Generator Owner to collect actual disturbance monitoring data following each voltage or frequency excursion.
9. We believe the mathematical symbol associated the 1.10 per unit voltage range listed in Attachment 1, Table 2, should be greater than and equal to" instead of just "greater than."

Likes 0	
Dislikes 0	

Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
See EEi comments	
Likes 0	
Dislikes 0	

Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
NRG Energy Inc is in support of the comments made by EPSA.	
Likes 0	
Dislikes 0	

Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	

(A) Duke Energy agrees with and supports EEI R4 comments for the three reasons cited by EEI because it is unclear how many existing resources can meet the frequency performance standards mandated in Requirement 3 and resource owners have not been given adequate time to fully assess the impact of imposing these new requirements on their existing resources,

(B) Duke Energy disagrees with the language in Measures 1-3 and recommends alternative language as stated below:

Measures 1-3 generally states:

“Each Generator Owner shall retain evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate the operation of each facility IBR did adhere to Ride□through requirements,” as specified in Requirement 1/2/3.

This statement requires heavy administrative burden and data storage since it would require capturing data daily and downloading the data to a storage location separate from the DDR,FR, & SER; since this equipment has low memory thresholds, memory could be exceeded. Accordingly, the TO/TOP would be required to notify the GO of a grid frequency event and data could be overwritten prior to TO/TOP notification.

Recommendation:

Each Generator Owner shall retain evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data, “upon notification for TO/TOP” to demonstrate the operation of each facility IBR did adhere to Ride□through requirements “or notification of data overwrite to TO/TOP.”

(C) Measure 1, 2 and 3 language is not consistent (suggested corrections added below):

- The word data was eliminated from M1: …Fault Recorder) “data” to demonstrate…

- The word ride-through was eliminated from M2: …IBR will adhere to “Ride-through” requirements, as specified in Requirement…

- Did the SDT intentionally substitute “performance” for “Ride-through requirements” in M2 – see second sentence excerpt below?

…each IBR did adhere to “Ride-through requirements”, as specified in Requirement…

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1

Answer	No
Document Name	

Comment

TEPC agrees with EEI's comments regarding PRC-029-1, requirement 4. EEI does not agree with imposing new unverified requirements on existing resources as proposed in PRC-029-1 because it is unclear how many existing resources can meet the frequency performance standards mandated in Requirement 3. We are additionally concerned because resource owners have not been given adequate time to fully assess the impact of imposing these new requirements on their existing resources, which align with IEEE 2800-2022 (See 7.3.2.1 Figure 12 & Table 15 (Frequency ride-through, page 80; and see 7.3.2.3.5 Rate of change of frequency (ROCOF), page 82), and did not exist as a Standard until February 2022, after most of these resources were built or placed in service. For this reason, we cannot support the approval of PRC-029-1 without the following changes to Requirement 4 ensure that existing resources that were not design and do not have the capability to meet these requirements are allowed to declare an exemption for frequency ride-through similar to what is provided for resources that cannot meet the voltage ride-through requirements.

Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	

AZPS Supports the following comments that were submitted by EEI on behalf of its members:

EEI does not agree with imposing new unverified requirements on existing resources as proposed in PRC-029-1 because it is unclear how many existing resources can meet the frequency performance standards mandated in Requirement 3. We are additionally concerned because resource owners have not been given adequate time to fully assess the impact of imposing these new requirements on their existing resources, which align with IEEE 2800-2022 (See 7.3.2.1 Figure 12 & Table 15 (Frequency ride-through, page 80; and see 7.3.2.3.5 Rate of change of frequency (ROCOF), page 82), and did not exist as a Standard until February 2022, after most of these resources were built or placed in service. For this reason, we cannot support the approval of PRC-029-1 without the following changes to Requirement 4 ensure that existing resources that were not design and do not have the capability to meet these requirements are allowed to declare an exemption for frequency ride-through similar to what is provided for resources that cannot meet the voltage ride-through requirements. See the proposed changes to R4 below:

R4. Each Generator Owner identifying an IBR that is in-service by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting voltage and frequency Ride-through criteria as detailed in Requirements R1**,** R2, and R3 and requires an exemption from specific Ride-through criteria shall*:*

4.1. Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1. This documentation shall include:

4.1.1 Identifying information of the IBR (name and facility #);

4.1.2 Which aspects of voltage or frequency Ride-through requirements that the IBR would be unable to meet and the capability of the hardware due to the limitation;

4.1.3 Identify the specific piece(s) of hardware causing the limitation;

4.1.4 Supporting technical documentation verifying the limitation is due to hardware that needs to be physically replaced or that the limitation cannot be removed by software updates or setting changes, and;

4.1.5 Information regarding any plans to remedy the hardware limitation (such as an estimated date).

4.2. Provide a copy of the information detailed in Requirement R4.1 to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA no later than 12 months following the effective date of PRC-029-1.

4.2.1 Any response to additional information requested by the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator (s), Reliability Coordinator(s), and the CEA shall be provided back to the requestor within 90 days of the request.

4.2.2 Provide a copy of the acceptance of a hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s).11

4.3. Each Generator Owner with a previously accepted limitation that replace the hardware causing the limitation shall document and communicate such a hardware change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the hardware change.

4.3.1 When existing hardware causing the limitation is replaced, the exemption for that Ride-through criteria no longer applies.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No

Document Name	
Comment	
Dominion Energy supports EEI comments. Current technology does not appear to support being able to fulfill these requirements on a go forward basis.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Please see additional comments in Question #3.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports the comments provided by the NAGF which state: *"…recommends that PRC-029 be revised to allow for frequency ride through ("FRT") exemptions to address such limitations for legacy IBR facilities. Not including FRT exemptions will result in a standard that will make certan IBR legacy facilities automatically non-compliant when the standards becomes effective.* *Requirement R3 – the NAGF is concerned that legacy IBR facilities are not capable of meeting the 5 Hz/second maximum ROCOF or the 25-degree phase angle jump requirements. Therefore, FRT exemptions are necessary and need to be included in Requirement R3.* *Requirement R4.2.2 – the NAGF is unclear as to what the Compliance Enforcement Authority (CEA) acceptance for a IBR hardware limitation exemption will consist of. Will the CEA provide an email response confiming acceptance to the Generator Owner submitting the exemption? How are such exemptions to be submitted and to whom within the CEA organization?*	
Likes 0	
Dislikes 0	
Response	

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	No
Document Name	
Comment	
Vistra supports comments made by AEP (Fultz)	
Likes 0	
Dislikes 0	
Response	

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
1. Requirement 2.1.3/2.2/2.5 - What does "other mechanisms" mean? Too vague. 2. Requirement 4.1.1 - change "facility #" to "facility unique identification number." 3. Requirement 4.2 - "CEA" is not defined in first instance of the acronym in the document. 4. Multiple Requirements list several points of contact for notification ("associated" PC, TP, TO, RC, CEA). This seems like a very long list of contacts that would likely lead to unnecessary PNCIs. Can this list be reduced?	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy does not agree with the current draft(3) of PRC-029-1.

FirstEnergy continues to request the DT consider changing PRC-029-1 Requirement R2, part 2.5, from 'Real Power' to 'Apparent Power'. To satisfy R2.5 as written, IBR sites would need to operate in static VAR control rather than automatic voltage control (adjusting VARs to control voltage). This would maintain a static power factor on the sites that would fail to provide effective voltage support due to manual intervention required to adjust VAR setpoint, not allowing for immediate response to voltage changes. This weakened response to voltage changes could result in less stable grid voltage, increasing potential for voltage trips, which does not align with the intent of the Standard. Changing this to 'Apparent Power' would make compliance more achievable while improving voltage support from IBR generators, enhancing IBR stability and reliability.

FirstEnergy also does not agree with the concept of 'Available Real Power' as used in R2.1.1 & R2.5 and defined in in footnotes 4 & 7 of Standard draft 3. Terminology/concepts critical for determining or maintaining compliance should be clearly defined in the NERC Glossary of Terms, not nested in a Standard footnote. For this term, specifically as it pertains to solar installations, the methods for measuring and approximating the 'Available' irradiance should be defined in detail as a Standard Attachment or preferably a Reliability Guideline. This guidance is required to create design specifications and ensure Owners/Operators consistently and uniformly quantify this resource for a given time and physical location. However, even with well-defined methods provided, it seems the ability of an Owner/Operator to definitively prove an exception in the case of solar would be challenging and difficult to audit; examples of evidence needed to properly justify an exception should be provided as guidance as well.

FirstEnergy also believes there could be a conflict between VAR-002 and PRC-029 for those IBR Resources meeting the applicability criteria of both Standards. VAR-002 requires generators to operate in automatic voltage control mode, adjusting reactive power output to control voltage. Adherence to PRC-029 R2.5 seems to directly conflict. This would require having alternative instructions from the TP/PC/RC/TOP, essentially granting an exception to one of the two Standards, to avoid a situation of non-compliance. Further clarification from the DT is warranted addressing the overlap/conflict between the two Standards and how an applicable IBR generator is to comply to both.

Likes 0	
Dislikes 0	

Response

Bruce Walkup - Arkansas Electric Cooperative Corporation - 6

Answer	No
Document Name	

Comment

1. "Removing Transmission Owners (TOs) from the applicability section places all accountability during voltage and frequency excursions on the IBR's Generator Owner (GO) regardless of the initial incident that starts the voltage or frequency excursion and regardless of who owns any impacted connecting equipment. This creates an inconsistency in compliance between PRC-024-4 and PRC-029-1."

2. "The new wording in Section 2.1.3 is unclear."

3. "Sections 2.1 and 2.2 are worded in a way that seems conflicting."

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

R1, R2 and R3 state, “Each Generator Owner shall ensure the design and operation is such…” Operation of the equipment is the GOP’s responsibility, not the GO’s. If the SDT’s intention was regarding the design of the system, AEP recommends revising the language to instead state, “Each Generator Owner shall ensure the *operational design* is such…”.

AEP recommends removing the phrase “demonstrate the design of each facility” from the proposed standard and returning to the original event-based requirements. The phrase may prove difficult to fully comply with, as a Functional Entity would have to know the design of the collector system and parameters and run the models correctly to demonstrate this. Much of this needed information would need to be provided by the manufacturer, which may require non-disclosure agreements.

There needs to be an exemption for system-related causes of ride-through failure. IBRs should be exempt from ride-through requirements in R1 through R3 if tripping or failure to ride through is attributable to any of the following:
1. Sub-synchronous control interaction or ferro-resonance involving series compensation confirmed by the TOP, RC, TP, or PC
2. Unstable behavior of other nearby IBRs or dynamic devices such as FACTS or HVDC confirmed by the TOP, RC, TP, or PC
3. System short circuit levels during contingencies below the level of IBR stable operation confirmed by the TOP, RC, TP, or PC
4. System-level transient or oscillatory instabilities confirmed by the TOP, RC, TP, or PC

AEP is concerned by the inclusion of the phrase “other mechanisms” in this standard, and recommend it be removed from Requirements 2.1.3, 2.2, and 2.5 as we believe it could be misinterpreted or misunderstood.

AEP believes the text “any response to additional information requested” in R 4.2.1 is confusing and should be clarified. AEP suggests it instead state “Additional information requested by the associated…”. In addition, Compliance Enforcement Authority should be spelled out in its entirety in its first use in the standard.

R4.2.2 states an obligation to “Provide a copy of the acceptance of a hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s).” AEP recommends that insight be provided in the Technical Rationale as to how the SDT envisions this acceptance process, and the timing thereof, would work.

Likes 0	
Dislikes 0	
Response	

Brian Lindsey - Entergy - 1	
Answer	No
Document Name	
Comment	

M1: This seems more like a requirement than a measure for meeting the requirement.

R2, M2, M3 and R4: Duplicative of Mod-026 and MOD-027. Also, seems to be dependent on PRC-028 passing and sites having DDRs installed.

R2 is not clear. It seems to overlap significantly with VAR-002.

R2.5 While the IBRs can respond quicker than 1 second and should be able to retore active power to the pre-disturbance level within that time-frame it may be difficult to have enough historian capability to ensure proper evidence.

R3 No provisions for exemptions for frequency limitations.

R4.1 thru 4.2: Are we seeking approval from this large list of entities for an exemption or are we documenting the limitation that prevents from meeting requirement 1? If we have to get approval there is no requirement in this standard that require any of these entities to provide that approval.

Recommend limiting who must be notified to just the TP or TP and RC. There needs to be a single point of contact instead multiple entities.

The CEA should not play a role in the acceptance or denial of limitations. Standards Drafting Teams have no authority to create requirements that the CEA must adhere to therefore, there are no penalties to the CEA if they do not provide an acceptance.

Likes 0	
Dislikes 0	

Response

Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3

Answer	No
Document Name	

Comment

SMEs responded with the following comments:

1. “Removing Transmission Owners (TOs) from the applicability section places all accountability during voltage and frequency excursions on the IBR’s Generator Owner (GO) regardless of the initial incident that starts the voltage or frequency excursion and regardless of who owns any impacted connecting equipment. This creates an inconsistency in compliance between PRC-024-4 and PRC-029-1.”
2. “The new wording in Section 2.1.3 is unclear.”
3. “Sections 2.1 and 2.2 are worded in a way that seems conflicting."

Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
The DT should cpnsider emphasizing the nature of the definition may not allow a single turbine or solar array to be lost in a System Disturbance (equates to failed "Ride-through" with loss).	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,Texas RE,NPCC,SERC,RF, Group Name SRC 2024	
Answer	Yes
Document Name	
Comment	
The SRC supports the addition of Part 4.2.2.: 4.2.2 Provide a copy of the acceptance of an hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s).	
Likes 0	

Dislikes 0	
Response	

Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	
Comment	

The work and efforts of this standard drafting team are much appreciated. Thank you for considering EPRI comments on the previous drafts as submitted previously. The new Draft 3 appears to be improved regarding internal consistency and alignment with requirements specified in voluntary industry standards, for example, IEEE 2800-2022. However, further improvements and alignment could be considered as follows:

A. General comments:

- Aligned with the directives to NERC in FERC order 901, the draft PRC-029 standard and the Implementation Plan for Project 2020-02 propose that the requirements apply to all applicable IBRs upon the standard's revised effective date or the newly added phased-in compliance dates. Applicable IBRs include existing (Legacy) IBRs that are already in operation prior to the specified dates. Requirement R4 provides a path for each Generator Owner to request a limited and documented exemption of a legacy IBR from the voltage ride-through criteria specified in R1 and R2. According to the Implementation Plan of Project 2020-02, "[o]ther NERC Standards Development projects will be pursued to address ongoing identification and mitigation of any potential reliability impacts to the BPS for such exemptions." A similar exemption from Requirement R3 that specifies applicable IBR frequency ride-through criteria is not possible according to the draft standard.
    - The proposed approach may require documentation of hardware limitations or reconfiguration for a significant number of legacy IBRs across North America. Neither the draft Technical Rationale nor the FERC record under RM22-12 present or cite sufficient technical evidence that supports this broad application of the proposed standard to existing IBRs in all applicable NERC regions.
    - International experience has shown that documentation of hardware limitations to support exemption from, or the retroactive application of similarly stringent ride-through capability requirements on legacy IBRs are associated with significant uncertainties, potential technical and procedural challenges, and costs. Justification of similarly ambitious regulations enforced in other countries required the production of evidence like post-mortem disturbance analysis or case studies that *quantified* the potential impact of non-compliant existing IBRs on the bulk power system stability and reliability.[1],[2]
    - Consequently, stakeholder concerns contribute to low approval rates for the draft PRC-029, possibly causing delays in moving the draft standard through the NERC process toward timely and effective enforcement for at least all new IBRs. Considering the approx. 2,600 GW of new IBRs in the interconnection queues across North America[3], these delays bear potentially significant risk for the BPS.
    - Furthermore, the proposed revised effective date and newly added phased-in compliance date of the capability-based elements of Requirements R1, R2, and R3 as specified in the draft PRC-029 are different from the transition periods found in international practice of similarly ambitious rule changes for new and IBRs (see the comments on Implementation Plan below for further details).
- The term Inverterbased Resource (IBR) to which the draft standard is intended to apply refers to proposed definitions being developed under the Project 202006 Verifications of Models and Data for Generators. Although the new draft includes redlines that strike the explicit mentioning of VSC-HVDC transmission facilities that are dedicated connections for IBR to the BPS, the definition proposed by Project 2020-06 is sufficiently broad that it could cover such facilities. For further clarity on the scope and application of the proposed PRC-029 standard, it could be helpful to add a clarifying sentence or to copy parts of Footnote 2 that clarifies the location of the "main power transformer" in case of IBR connecting via a dedicated VSC-HVDC transmission facility into the terms section on page 2 of the standard.
- For the purpose of clarity, harmonization, and compliance of IBR across North America, proposed requirements could even further align with requirements that are testable and verifiable as specified in voluntary industry standards developed through an open process such as ANSI, CIGRE, IEC, or IEEE. The drafting team is encouraged to review these standards and where applicable further align, for example:
    - Requirement R1 and R2 relate to IEEE Std 2800™-2022, Clause 7.2.2 (Voltage disturbance ride-through requirements), with consideration of Clause 7.3.2.4 (Voltage phase angle changes ride-through) as a stated exception in R1.
    - Requirement R3 relates to IEEE Std 2800™-2022, Clause 7.3.2 (Frequency disturbance ride-through requirements), with consideration of Clause 7.3.2.3.5 (Rate of change of frequency (ROCOF) ride-through) as a stated exception in R3.
    - Measures M1–M3 relate to IEEE P2800.2 Draft 1.0a, Clause 5 (Type tests), Clause 6 (Validation procedures for IBR unit models and

    - supplemental IBR device models), and Clause 7 (Design evaluations), Clause 8 (As-built installation evaluations), Clause 9 (Commissioning tests), Clause 10 (Post commission model validation), and Clause 11 (Post-commissioning monitoring).
    - Measure M4, additionally, relates to IEEE P2800.2 Draft 1.0a, Clause 12 (Periodic tests), and Clause 13 (Periodic verification).
- The draft standard does not specify grid conditions for which the specified ride-through requirements apply. During its lifetime, a plant may experience many different operational conditions, along with changes to the grid, and may fail to ride-through an event if the plant was operating in a grid condition vastly different from that which it was designed for. The standard could include an exception for such situations based on leading industry practices, or a requirement for the TP, PC, etc. to specify such an exception.
- IEEE 2800-2022 allows for an exception for "self-protection" when negative-sequence voltage is greater than specified duration and threshold within continuous operation region. There is no such exception in draft PRC-029. Such an exception may be necessary for type III wind turbine generator (WTG) based plants.
- Standard does not allow any flexibility for failure of ride-through resulting from misoperation of protection system. The misoperation of protection system may occur for many reasons over the life of a plant. For example, for a fault on a transmission system, if differential protection for the main step-up transformer misoperates due to environmental issues such as damage due to water from a leaking roof or animal intrusion, then plant would be considered out of compliance. If a synchronous machine based generating plant trips because of similar issue, it would not be out of compliance with PRC-024.
- Requirements R1–R4 call out both "design and operation". If the plant is designed to ride-through, then is it necessary to specifically call out and include IBR "operation" into the scope of PRC-029?
    - The inclusion of "operation" in PRC-029 would put a Generator Owner out of compliance with the standard whenever one of their IBR plants fails to ride-through real world disturbances, including incidents where failure of ride-through within the specified abnormal voltage and frequency conditions was beyond the GO's control.
    - An alternative approach could be to narrow the scope of PRC-029 to require a Generator Owner to adequately *design* each IBR *to have the capability* to ride-through the specified abnormal conditions. The GO could then be further required by PRC-028 and PRC-030 to monitor IBR performance during operations and for real world events. If an IBR was found to have failed ride-through during operations, then PRC-030 could require the GO to identify the underlying issues and to take corrective action.

B. Ride-through definition

- Consider adopting definition from IEEE 2800, which is from IEEE 1547, and well understood by the industry.

C. Requirement R1:

- Requirement calls out "design and operation". If the plant is designed to ride-through then is it necessary to specifically call out "operation"?
    - The Reliability Standard PRC-006, Requirement R3, requires PC to develop UFLS program. Several assumptions are made here. If an event occurs, then R11 requires assessment of an event and if deficiency in UFLS program is identified then PC is required to consider deficiencies in R12. If UFLS program was deficient then PC is not out of compliance with R3 (or any other requirements in the standard). This is a good-faith approach: Design UFLS program and if actual event shows deficiency in UFLS Program then fix it. No compliance issues, as far as UFLS program was designed per Requirement R3.
    - Same approach could be taken in PRC-029, where R1 could require that plant is designed to ride-through specified voltage disturbance. The PRC-028 and PRC-030 then requires monitoring of plant performance and take corrective actions when necessary.
    - The same approach could be extended to requirements R2 and R3.
- If IBR operation remains within the scope of PRC-029, then consider revising the beginning of the sentence as following for better readability: *Each Generator Owner shall design and operate each IBR to meet or exceed Ride-through requirements…*
    - The same changes could be extended to requirements R2 and R3.

D. Requirement R2

- Refer to comments on R1 that could be extended to requirement R2.

E. Requirement R2, Part 2.1

- Why is it necessary to specify a performance requirement when voltage is in the continuous operation region? The standard remains silent on performance expectation for frequency ride-through requirements. For performance requirement for voltage ride-through mandatory operation region is also very brief. The intent of this standard is to focus on ride-through during voltage and frequency disturbances. If there is a desire to address performance then one option could be to simply state that performance shall be as specified by TP, PC, etc. That is in Part 2.1.3 anyway.
- Part 2.1.2: remove “and according to its controller settings”. It is not incorrect but “according to its controller settings” inherently apply to all performance requirements.
- Part 2.1.3: this requirement in IEEE 2800 was necessary and was tied to reactive power capability requirement as shown in Figure 8 of IEEE 2800. Given PRC-029 does not include reactive power capability requirements, perhaps PRC-029 could remain silent.

F. Requirement R2, Part 2.2

- Part 2.2 applies at the high-side of the main power transformer. The IBR is required to exchange current, up to the maximum capability. How is the “maximum capability” of an IBR determined? There could be some explanation, perhaps with examples, in the technical rationale document.
- The phrase “provide voltage support on affected phases during both symmetrical and unsymmetrical voltage disturbances” is confusing.
    - It is understood that intent is to require to inject “unbalanced current” or “negative-sequence” current during asymmetrical faults. However, as written, injection of balanced reactive current into an unbalanced fault meets the requirement to provide voltage support on affected phases, in addition to unaffected phase. The standard does not prohibit voltage support on unaffected phases. The voltage support on unaffected phase is usually problematic. But the requirement, as written, does not prohibit this.
    - During a L-G fault, current in a faulted phase is dependent on transformer winding configuration. Does this requirement, unintentionally, specify specific transformer configuration?
- During mandatory operation, voltage is abnormal and could be almost zero for close-in faults. As such, “current” over “power” is more appropriate. Power in faulted and unfaulted phases could be different as well. Replace real and reactive power with active (real) and reactive current respectively.

G. Requirement R2, Part 2.3.1

- Per language in attachment 1, permissive operation is allowed when line-to-ground or line-to-line voltage is below 10%. But per Part 2.3.1, IBR is required to restart current exchange when positive-sequence voltage enters continuous or mandatory operation region. This is conflicting. For example, for a line-to-ground fault on high-side terminals of main power transformer, the positive-sequence voltage would be more than 10%, i.e., in the mandatory operation region.

H. Requirement R2, Part 2.4

- The intent of this requirement is understood. However, if there are multiple plants in the area, then one plant misbehaving may cause overvoltage on high-side terminals of the main power transformer of other plants in the area. Also, the post-fault dynamics greatly depend on system operating condition (peak, shoulder, off-peak, etc.) along with transmission outages, status of capacitor banks, etc. The Generator Owner usually does not have system data to evaluate post-fault system dynamics and to determine if plant’s behavior is or not a contributing factor to overvoltage.

I. Requirement R3

- Refer to comments on R1 that could be extended to requirement R3.
- The proposed frequency ride-through requirement is more stringent than the applicable requirement in IEEE Std 2800-2022. The justification provided in the technical rationale is based on engineering judgement with no provided substantiating studies. Furthermore, the PRC-006

requires the design of UFLS program to keep frequency withing certain bounds. Requiring IBRs to ride-through a slightly more frequency deviation compared to frequency deviation band allowed in PRC-006 seems reasonable. However, the proposed frequency ride-through requirement is much more stringent. Consider aligning with IEEE Std 2800 frequency ride-through requirement as a minimum requirement and let regions specify more stringent requirements where justified.

- The standard does not allow exception for frequency ride-through requirements. While the physical strain on legacy IBR plants to ride-through frequency disturbances may be less significant compared to the strain during voltage ride-through, the capabilities of legacy IBR hardware (including wind-turbine generators, inverters, transformers, and auxiliary equipment like fans and pumps for cooling, if present) are, at best, uncertain. For plants in commercial operation before the effective date of this standard, installed equipment may not have been tested to the specified frequency ride-through capability and that could make determining if a legacy IBR plant would be able to ride-through proposed frequency ride-through requirements challenging.
    - The SDT points to directive in FERC order 901 and states that order 901 does not allow exception for frequency ride-through. However, order 901 does not require frequency ride-through requirements as stringent as the ones proposed.
    - It is also not clear to us from the record in RM22-12 whether FERC intentionally limited the exemption from ride-through to only voltage ride-through, and on what technical grounds the exemption did not also include frequency ride-through.[4],[5],[6]
- Footnote 9 could be simplified as following: *The ROCOF is an average rate of change of frequency over an averaging window of at least 0.1 second.*

J. Requirement R4

- We re-iterate the following observations related to the Effective Date and Phased-in Compliance Dates stated in the Implementation Plan of the project, as previously offered in our EPRI comments on the initial draft of PRC-029:

o Aligned with the directives to NERC in FERC order 901, the draft proposes that all requirements specified in PRC-029 apply to all applicable IBRs upon the standard's effective date, including Legacy IBRs that were already in operation prior to that date. This approach may require reconfiguration or documentation of hardware limitations for a significant number of existing IBRs across North America. In some cases, for example where the original equipment manufacturer (OEM) of hardware used in Legacy IBRs has gone out of business, or the OEM has ceased to support a legacy hardware product line, documentation of hardware limitations and development of models accurately representing Legacy IBR performance may be challenging. Additional exemptions to address these challenges could be included in R4 of the draft standard or the implementation plan.

o One example for an alternative approach to the one proposed in the draft PRC-029 could be that TOs and reliability coordinators were to discern on a regional or case-by-case basis about the application of PRC-029 to Legacy IBRs, preferably based on technical evidence like case studies assessing and quantifying the potential BPS reliability impacts from Legacy IBR in their regions.[7] If documentation of Legacy IBR hardware limitations was not available, worst-case assumptions could be made in these case studies. If such studies indicated a viable reliability risk, R4 could be applied to selected or all Legacy IBRs. This could produce documentation of hardware limitations to refine study assumptions to produce more realistic case study results. If refined results still indicated a viable reliability risk, R1-R3 could be applied to Legacy IBRs selectively.

- We refer to our questioning of FERC's intentionality with not including an exemption for frequency ride-through capability per our comments on Requirement R3 above.
- For further comments on the Effective Date and Phased-in Compliance Dates refer to below comments on the Implementation Plan.
- Parts 4.1 and 4.2 refers to exemption for a plant but part 4.3 refers to hardware in plant. If few of many wind-turbine generators in a plant are replaced, then plant still has limitation because most of the wind-turbine generators still have limited capability. Perhaps some clarification could be added that if "all hardware with documented capability limitation" is replaced, only then an exemption for a legacy IBR would not apply any longer.

K. Violation Risk Factors

- The language for the assignment of a VRF to Requirement R4 in the draft standard is truncated. Consider revising to: *[Violation Risk Factor: Lower]*
- Each Generator Owner is required per Requirement R4 to identify, document, and communicate about legacy IBRs that have hardware limitations related to the voltage ride-through criteria specified in R1 and R2. Why is a VRF of "Lower" assigned to R4 and not a VRF of "Medium"? Could the uncertainty related to the capability and performance of legacy IBRs associated with a violation of R4 (a requirement that is administrative in nature and a requirement in a planning time frame) by a Generator Owner not, under the abnormal conditions, be expected to

directly and adversely affect the electrical state or capability of the Bulk Power System, or the ability to effectively control the Bulk Power System?

L. Violation Severity Levels

- R1, R2, and R3: The lower VSL for each of these requirements is for failure to demonstrate the design capability to ride-through. There are two reasons for which this could arise:

(1) Plant is capable to ride-through but is not demonstrated in design evaluation or interconnection studies.

(2) Plant is not capable to ride-through and that is demonstrated in design evaluation or interconnection studies.

- Reason (1) is not a problem for grid reliability, it is just that studies are not adequate to demonstrate ride-through capability, and hence lower VSL is justified. But reason (2) is not any different from a case in severe VSL where an entity fails to demonstrate that IBR adhered to ride-through requirements (based on actual system disturbance event data).
- The VSLs could be rephrased to read:
    - Lower VSL: *The Generator Owner failed to produce adequate evidence demonstrating for each applicable IBR that it was designed to Ride-through in accordance with …*
    - Severe VSL: *The Generator Owner either produced evidence demonstrating for any of their applicable IBR that it was not adequately designed to adhere to Ride-through, or the Generator Owner failed to produce evidence of actual disturbance monitoring data for a specific event that demonstrate each applicable IBR adhered to Ride-through requirements in accordance with …*

M. Attachment 1

- Tables 1 and 2 are inconsistent. Table 1 states “>= 1.10” whereas Table 2 states “>1.10”.
- Clarify that cumulative window, for voltage band where ride-through duration is 1800-second, is 3600-second. Also, consider clarifying that 1800-second ride-through duration is only applicable to nominal voltages other than 500 kV.
- Numbered item #3: states that applicable voltage is “… on the AC side of the transformer(s) that is (are) used to connect…..”. Both sides of transformer are AC, one is on DC-AC converter side and another on AC grid side. As written, voltage on either side of transformer is applicable. Please clarify that applicable voltage is on AC “grid” side of the transformer.
- Numbered item #5: Consider revising as following - *The applicable voltage for Tables 1 and 2 is identified as the voltage max/min of phase-to-[strike: neutral] [add: ground] or phase-to-phase fundamental [add: frequency] root mean square (RMS) voltage at the high-side of the main power transformer.*
- Numbered item #7: The interpretation of ride-through curves/points needs further clarification. Would a wind-based IBR plant be required to ride-through an event where at t=0 voltage drops from nominal to zero, then @t=0.16 s voltage rises to 25%, @t=1.2 s voltage rises to 50%, @t=2.5 s voltage rises to 70%, @t=3 s voltage rises to 90%? The item (8) is also tied to item (12), where a combined “area” is stated. Does must ride-through zone represent an “area” (represented by deviation in voltage multiplied by time duration)? Consider adding a few examples in the technical rationale.
    - Note that IEEE 2800-2022, informative Annex D, Section D.1 (Interpretation of voltage ride-through capability requirements specifies) states that the interpretation used in the standard is a “voltage versus time curve.” However, the same Annex includes a Figure D.4 that intends to show “a realistic and complex trajectory of a voltage during a disturbance” for which the informative annex then further states that an IBR plant “is required to ride through,” effectively interpreting the IEEE 2800-2022 ride-through curves as a “voltage versus time envelope.” Thus, there seems to be some ambiguity in IEEE 2800-2022 as to how to interpret its ride-through curves, a finding that could be considered and resolved in a potential future revision or amendment of IEEE 2800.
    - If the voltage ride-through requirements proposed in Attachment 1 were to be specified or interpreted as a “voltage versus time envelope,”, and considering that an unknown number of IEEE SA balloters that voted affirmatively on IEEE 2800-2022 may have interpreted the IEEE 2800-2022 requirements as the less stringent “voltage versus time curves” explained in Annex D of the standard, the proposed PRC-029 could be perceived as more stringent than IEEE 2800-2022.
    - Adding a few examples in the technical rationale could help clarify the correct interpretation of the voltage ride-through curves specified in Attachment 1.

- Numbered item 10: Please clarify if this statement applies to protection applied to high side of main power transformer only OR everywhere in the plant.

N. Attachment 2:

- Table 3: To be consistent with other frequency thresholds, could “> 61.2” be “>= 61.2” instead. If so, range for continuous operation then be “< 61.2 and > 58.8”.
- Consider adding a statement that frequency ride-through requirements apply only when voltage is in the must ride-through zone.
- Numbered item 3: What is meant by control settings? Is the intent to state protection settings instead?

O. Implementation Plan

- The proposed revised effective date and newly added phased-in compliance date of the capability-based elements of Requirements R1, R2, and R3 as specified in PRC-029-1 *for primarily new IBRs* of,
  - “the first day of the first calendar quarter that is *twelve months [emphasis added by EPRI]* after” either “the effective date of the applicable governmental authority’s order approving” or “the date the standard is adopted by the NERC Board of Trustees” for (primarily new) Bulk Electric System IBRs, and
  - “until the later of: (1) January 1, 2027; or (2) the effective date of the standard” for (primarily new) Applicable Non-BES IBRs

are different from transition periods found in international practice of similarly significant rule changes for new IBRs. Examples for reference include, but are not limited to:

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  - (European) Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators, Article 72 (Entry into force) states, “the requirements of this Regulation shall apply from *three years [emphasis added by EPRI]* after publication.” [8]
  - German Government, “Verordnung zu Systemdienstleistungen durch Windenergieanlagen (Systemdienstleistungsverordnung – SDLWindV) (Ordinance for Ancillary Services of Wind Power Plants (Ancillary Services Ordinance - SDLWindV),”[9]

\- Mandatory requirement for new wind power plants to meet specified requirements by March 31, 2011, i.e., *19 months* after ordinance entered into force.

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  - ERCOT, “Issue NOGRR245. Inverter-Based Resource (IBR) Ride-Through Requirements. Report of Board Meeting on June 18, 2024,”[10] and ERCOT, “Nodal Operating Guide Revision Request (NOGRR) 245, Inverter-Based Resource (IBR) Ride-Through Requirements. ERCOT Update,” August 8, 2024.”[11]

\- All new IBRs with a Standard Generation Interconnection Agreement (SGIA) after August 1, 2024, i.e., *immediately once the NOGRR enters into force* (subject to change until ERCOT board approval and until there is a non-appealable Public Utility Commission of Texas (PUCT) final order is in place)

\- Extension of exemption from requirements new IBRs with a Standard Generation Interconnection Agreement (SGIA) after August 1, 2024, does not exceed December 31, 2028, i.e., *4 years and 4 months* (subject to change until ERCOT board approval and until there is a non-appealable Public Utility Commission of Texas (PUCT) final order is in place)

- The proposed revised effective date and newly added phased-in compliance date of the Requirement R4 as specified in PRC-029-1 *for primarily legacy IBRs* of,
  - “the first day of the first calendar quarter that is *twelve months [emphasis added by EPRI]* after” either “the effective date of the applicable governmental authority’s order approving” or “the date the standard is adopted by the NERC Board of Trustees” for (primarily legacy) Bulk Electric System IBRs, and

- ◦ “until the later of: (1) January 1, 2027; or (2) the effective date of the standard” for (primarily legacy) Applicable Non-BES IBRs

are either not applicable, or—for re-configurations that do not require replacement of hardware—comparable, or—for retrofits that do require replacement of hardware—they are different from transition periods found in national and international practice of similarly significant retro-active enforcements for legacy IBRs. Examples for reference include, but are not limited to:

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    - (European) Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators, Article 4 (Application to existing power-generating modules) states, [12]

- “Existing power-generating modules are not subject to the requirements of this Regulation, except where: … .”

- “For the purposes of this Regulation, a power-generating module shall be considered existing if:

· (a) it is already connected to the network on the date of entry into force of this Regulation; or

· (b) the power-generating facility owner has concluded a final and binding contract for the purchase of the main generating plant by *two years [emphasis added by EPRI]* after the entry into force of the Regulation.

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    - German Government, “Verordnung zu Systemdienstleistungen durch Windenergieanlagen (Systemdienstleistungsverordnung – SDLWindV) (Ordinance for Ancillary Services of Wind Power Plants (Ancillary Services Ordinance – SDLWindV)),”[13]

- Financial incentive for voluntary retrofits of legacy wind power plants between July 11, 2009, and January 1, 2011, i.e., *1.5-years*.

-
    - German Government, “Verordnung zur Gewährleistung der technischen Sicherheit und Systemstabilität des Elektrizitätsversorgungsnetzes (Systemstabilitätsverordnung - SysStabV) (System Stability Regulation – SysStabV)),“[14]

- Mandatory requirement for reconfiguration of legacy IBRs and distributed energy resources (DERs) larger than 100 kW by August 31, 2013, i.e., *13 months* after ordinance entered into force.

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    - ERCOT, “Issue NOGRR245. Inverter-Based Resource (IBR) Ride-Through Requirements. Report of Board Meeting on June 18, 2024,”[15] and ERCOT, “Nodal Operating Guide Revision Request (NOGRR) 245, Inverter-Based Resource (IBR) Ride-Through Requirements. ERCOT Update,” August 8, 2024.”[16]

- Mandatory requirement for legacy IBRs with an SGIA executed prior to August 1, 2024 to maximize the performance of their protection systems, controls, and other plant equipment (within equipment limitations) to achieve, as close as reasonably possible, the capability and performance set forth in IEEE 2800-2022 no later than December 31, 2025, i.e., *17 months* after NOGRR enters into force.

- Extension of exemption from requirements for legacy IBRs with a Standard Generation Interconnection Agreement (SGIA) prior to August 1, 2024, does not exceed December 31, 2027, i.e., *3 years and 4 months* (subject to change until ERCOT board approval and until there is a non-appealable Public Utility Commission of Texas (PUCT) final order is in place)

- The first use of the word “or” in the sentence under the section Effective Date and Phased-in Compliance Dates, PRC-029-1 Phased-in Compliance Dates, Requirement 4, Applicable Non-BES IBRs on page 5 of the Implementation Plan could be replaced for clarity with the word “for” to then read: *Entities shall not be required to comply with Requirement R4 for their non-BES IBRs until the later of: (1) January 1, 2027; or (2) the effective date of the standard.*

P. Technical Rationale

- IEEE Std 2800™-2022, a voluntary industry standard for *Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems* is mentioned in the Technical Rationale document for PRC-029-1 but not cited properly. In all instances where the document refers to that IEEE standard, referencing could be improved by following our guidance offered below. Where appropriate, reference to and proper citation of IEEE P2800.2, an active IEEE Standards Association project for developing of a *Recommended Practice for Test and Verification Procedures for Inverter-based Resources (IBRs) Interconnecting with Bulk Power Systems*, may serve as an additional reference.
    - Suggested referencing of IEEE Std 2800™-2022:

- For the initial citation within any document, we suggest citing the standard as follows: IEEE Std 2800™, IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems

- Subsequent mentions of the standard could refer to it as: IEEE 2800

-
    - Similar guidelines could be applied to IEEE Std 2800.2™:

- We recommend citing the standard in full on first reference as: IEEE P2800.2, Draft Recommended Practice for Test and Verification Procedures for Inverter-based Resources (IBRs) Interconnecting with Bulk Power Systems

- Followed by subsequent mentions as: IEEE P2800.2

- Considering the explicit statements in the "PRC-029-1_Technical_Rationale" document about the intended alignment with IEEE Std 2800™-2022 requirements in formulating the technical content of PRC-029-1 by the drafting team, references to specific clauses of IEEE Std 2800™-2022 could provide more clarity to industry stakeholders about which parts of the IEEE standard the PRC-029-1 aims to incorporate. It may also be helpful to identify areas where they are not aligned. Refer to the examples in our general comments above.
- IEEE 2800-2022 may not be the only industry standard with scope that overlaps with the proposed PRC-029 standard. ANSI and CIGRE currently may not have related standards. While IEC does have standards and technical specifications with related scope, these documents tend to be less specific in their technical requirements compared to IEEE standards like IEEE 2800-2022.[17]

Q. Justifications

- The table for “VRF Justifications for PRC-029-1, Requirement R3” on page 11 of the Justifications lists a Proposed VRF of “Lower”; but the draft PRC-029 standard assigns R3 a “[Violation Risk Factor: High]”. Consider resolving inconsistency across the two documents.
- Refer further to the comment on the VRF assignment for Requirement R4 above.

[1] Grid Codes for Interconnection of Inverter-Based Distributed Energy Resources by Country: Recent Trends and Developments. EPRI. Palo Alto, CA: November 2014. 3002003283. [Online] https://www.epri.com/research/products/000000003002003283 (last accessed, January 24, 2023)

[2] Dispersed Generation Impact on CE Region Security: Dynamic Study. 2014 Report Update. European Network of Transmission System Operators for Electricity (ENTSO-E), ENTSO-E SPD Report, Brussels, Belgium: December 2014. [Online] https://eepublicdownloads.entsoe.eu/clean-documents/Publications/SOC/Continental_Europe/141113_Dispersed_Generation_Impact_on_Continental_Europe_Region_Security.pdf (last accessed, January 24, 2023)

[3] LBNL (2024) [Online] https://emp.lbl.gov/generation-storage-and-hybrid-capacity

[4] E-1-RM22-12-000.pdf [Online] https://www.ferc.gov/media/e-1-rm22-12-000 (last accessed, August 6, 2024)

[5] 20230206-5094_ACP-SEIA IBR NOPR comments (Final).pdf [Online] https://elibrary.ferc.gov/eLibrary/filedownload?fileid=49DB8845-A3E3-CEEA-A6D8-86289C500000 (last accessed, August 6, 2024)

[6] E-2-RM22-12-000.pdf [Online] https://www.ferc.gov/media/e-2-rm22-12-000 (last accessed, August 6, 2024)

[7] EPRI is currently working on case studies relevant to these topics and is also aware of others doing similar work.

[8] ENTSO-E: Requirements for Generators. [Online] https://www.entsoe.eu/network_codes/rfg/ (last accessed, August 6, 2024)

[9] Federal Law Gazette I (no. 39) (2009): 1734–46. [Online] https://www.clearingstelle-eeg-kwkg.de/gesetz/695 (last accessed, August 6, 2024)

[10] ERCOT, "Issue NOGRR245. [Online] https://www.ercot.com/mktrules/issues/NOGRR245 (last accessed, August 9, 2024)

[11] ERCOT, "Nodal Operating Guide Revision Request (NOGRR) 245, Inverter-Based Resource (IBR) Ride-Through Requirements. ERCOT Update," August 8, 2024 [Online] https://www.ercot.com/calendar/08082024-NOGRR245-_-Review-of (last accessed, August 9, 2024)

[12] Ref. Footnote 10

[13] Federal Law Gazette I (no. 39) (2009): 1734–46. [Online] https://www.clearingstelle-eeg-kwkg.de/gesetz/695 (last accessed, August 6, 2024)

[14] Federal Law Gazette I (no. 40) (2012): 1635. [Online] https://www.gesetze-im-internet.de/sysstabv/BJNR163510012.html (last accessed, August 6, 2024)

[15] Ref. Footnote 16

[16] Ref. Footnote 17

[17] Example IEC standards and technical specifications with related scope may include IEC 61400-27, IEC 62934:2021, IEC TS 63102:2021, and IEC TR 63401-4:2022.

Likes 0	
Dislikes 0	

Response

Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC

Answer	Yes
Document Name	

Comment

PNM agrees with the comments of EEI.

Likes 0	
Dislikes 0	

Response

Nick Leathers - Ameren - Ameren Services - 3 - SERC

Answer	Yes

Document Name	
Comment	

Ameren recommends that the drafting team clarify the phrase "current block mode." Additionally, there is some concern that the technical requirements are so rigid that it might become challenging for utilities to implement a cost effective solution for the entity and customers. Additionally, Ameren supports the responses from both EEI and NAGF for this question.

R1, bullet point #2:

R1 suggests that we have to set protection so that we do not trip until capabilities are exceeded, which is not how Ameren sets protection. Ameren sets protection systems to operate before capabilities of equipment are exceeded. In addition, engineers should be setting relays per capabilities of equipment to prevent damage and to maximize their capability. We do not suggest using a generic capability when equipment may have higher capabilities. We suggest replacing the second bullet with the following and removing the last bullet.

"The applicable in-service protection system devices are set to operate to isolate or de-energize equipment in order to limit or prevent damage when the voltage or Volts per Hz (V/Hz) at the high-side of the main power transformer exceed accepted equipment capabilities in accordance with requirement R4; or"

Then add a footnote:

"If the Volts per Hz (V/Hz) withstand capability of the main power transformer is not available for an existing facility, then the applicable in-service protection system may be set to isolate or de-energize equipment if the volts per Hz at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per-unit for longer than 2 seconds"

R4, 4.1.2:

In Ameren's experience, manufacturers are unwilling to share hardware capabilities on the inverter and claim it is proprietary or some other reason. We suggest a re-write of 4.1.2 to add an exclusion such as the following:

"...If the Functional Entity has requested the capability of the hardware limitation, but the manufacturer will not provide the capability, the Functional Entity must provide evidence that they have made the effort to request this information from the manufacturer and provide this in lieu of the capability."

Ameren requests the SDT to provide 2 years to verify compliance with R1, R2, R3 and R4 of the standard since the requirements are extensive.

Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Greg Sorenson - Greg Sorenson On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	

MISO supports the addition of Part 4.2.2.:

4.2.2 Provide a copy of the acceptance of an hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s).

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

Southern Company appreciates the work of the SDT but would like to offer the follwing changes for consideration:

- There is a risk that changes to the IBR definition under Project 2020-06 may alter the definition for that contained in PRC-029, thus complicating standard implementation.
- Without providing technical justification, a FRT curve is more stringent than IEEE2800. In addition, industry has not been provided with any technical studies justifying the need for the proposed 6-second FRT bands. Southern Company recommends that the SDT align the FRT requirements with IEEE 2800. Individual Regions should be allowed to adopt more stringent FRT standards based on their respective system needs and resource capabilities.
- There is no technical justification for **No FRT** exemptions. (other than the "Regulatory Rationale" provided from FERC 901 Order). Section 215(d)(2) of the FPA requires FERC to give "due weight" to the technical expertise of the ERO when evaluating the content of a proposed Reliability Standard or modification to a Standard.
- The ROCOF requirement may be infeasible for certain legacy IBRs that are unable to disable ROCOF protection and distinguish between fault and non-fault conditions.
- Table 1 and 2 footnote 6 states that the voltage ride through charts are only valid when frequency is within the "must Ride-through zone" as specified in Figure 1 of Attachment 2. The SDT should add a similar footnote to Attachment 2 Table 3 FRT table stating that the frequency ride through charts are only valid when voltage is within the "must Ride-through zone". Illustrated in the Voltage Ride-through figures.
- In the Implementation Plan, Southern Company recommends extending the capability due date from 12 months of effective date of standard to 18 – 24 months due to expected complexity of solution development and deployment.

Likes 0	
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	
Document Name	

Comment

NRG agrees with and refers the SDT to the EPSA comments.

Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE has the following clarifying comments on PRC-029-1:

- Texas RE recommends correcting Requirement R2 subpart 2.3.1:

2.3.1 If a **an** IBR enters current blocking mode, it shall restart current exchange in less than or equal to five cycles of positive sequence voltage returning to a continuous operation region or mandatory operation region

- In Requirement Part 4.1.1, Texas RE recommends changing “facility #” to “facility unique identifier” or “facility unique number”.
- Texas RE recommends Compliance Enforcement Authority (CEA) should be spelled out in Requirement R4 subpart 4.2 since it is the first time seeing that term in the requirement language.

Likes 0	
Dislikes 0	
Response	

3. Provide any additional comments for the Drafting Team to consider, if desired.

Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	

Document Name	
Comment	

Section 4: Applicability:

4.2 is not aligned with the PRC-028. The DT should consider the alignment of the applicability section between all IBR standards.

1) It is not clear what “The Elements associated with..” means in 4.2.1. Does it mean power system elements?

R2:

The new wording in Section 2.1.3 is unclear.

MH recommends it be changed to “Prioritize Real Power or Reactive Power delivery when the voltage is less than 0.95 per unit, the voltage is within the continuous operating region, and the IBR cannot deliver both Real Power and Reactive Power due to a current limit or Reactive Power limit unless otherwise specified through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.”

R3:

MH is still concerned with the lack of provisions for exemptions for frequency limitation (RoCoF) that may put some of the legacy IBR in a non-compliant state and may require a costly upgrade to meet R3 requirements.

MH recommends the following:

Extending the implementation date for R3 for legacy IBR to 18 months

or/and

Lowering the RoCoF for legacy IBR from 5 Hz /second to 3Hz/ second

R4:

The CEA is not a defined NERC term in the Glossary of Terms Used in NERC standard list, MH recommends spelled out Compliance Enforcement Authority (CEA) in Requirement R4 subpart 4.2 since it is the first time seeing that term in the requirement language.

Attachment #1:

MH agrees with removing the previous figures 1 and 2 from attachment # 1 but we recommend adding at least three voltage waveform examples into TR to illustrate how the Table 1 and 2 should be used to determine the compliance with voltage ride through

TR:

More information should be added to some frequency waveform examples in TR to illustrate how to calculate the RoCoF

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	
Document Name	

Comment

Tri-State agrees with the additional comments provided by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	
Document Name	

Comment

Dominion Energy supports EEI comments.

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	

Document Name	
Comment	

AZPS supports the following comments that were submitted by EEI on behalf of its members:

EEI offers the following additional comments on the proposed 3rd draft of PRC-029-1:

· EEI does not support the inclusion of the phrase “The Elements associated with” as contained in the Facilities Section (4.2.1). The inclusion of this phrase expands the scope in ways that are unclear creating unnecessary compliance confusion.

· Bullet 1 under Requirement R1 is unnecessary and should be deleted, noting that facilities are never obligated to stay connected to a fault.

· EEI asks that the DT provide additional clarity to Requirement R4, subpart 4.2.2 noting that there is insufficient clarity regarding what is needed to support a hardware limitation and what the deadline is for the submission of a limitation.

Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	

Duke Energy agrees with and supports submitted EEI Additional Comments.

Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	

none

Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	
Document Name	
Comment	

The language in **Section 4, Applicability** does not match the language used in the latest proposed version of PRC-028-1. Although the language in PRC-029-1 is cleaner and preferred, it is not quite clear what is meant by the inclusion of the words “The Elements associated with” in Section 4.2.1. These words are unnecessary.

SMUD would prefer that the drafting team delete these words and change Section 4, Applicablity to the language below. The language used in Section 4, Applicability for the currently proposed PRC-028-1, PRC-029-1 and PRC-030-1 should match. This change is non-substantive and could be made in the final ballot.

The existing language in PRC-029-1 (and PRC-030-1) is as follows:

4.1 Functional Entities:

4.1.1. Generator Owner

4.2 Facilities:

4.2.1. ***The Elements associated with*** (1) Bulk Electric System (BES) IBRs; and (2) Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

The existing language in PRC-028-1 is as follows:

4.1. Functional Entities:

4.1.1. Generator Owner that owns equipment as identified in section 4.2

4.2. Facilities:

4.2.1 BES Inverter-Based Resources

4.2.2 Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV

SMUD’s preferred language in PRC-029-1 Section 4, Applicability is as follows:

4.1 Functional Entities:

4.1.1. Generator Owner

4.2. Facilities:

4.2.1 BES Inverter-Based Resources

4.2.2 Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

SMUD also agrees with the comments submitted by the MRO NSRF on Requirements R2, R3, R4, and Attachment 1.

Likes 0	

Dislikes 0	
Response	
Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	
Document Name	
Comment	
NV Energy agrees with the NSRF comments especially on the lack of exceptions for legacy IBR systems (R3)	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
1. We believe NERC should coordinate the Implementation Plans for the three standard development projects associated with Milestone 2 of its work plan to address the directives within FERC Order No. 901. This would give most Generator Owners one set of compliance implementation dates to track. The phased-in compliance dates should align with those proposed under NERC Standard Development Project 2021-04, Reliability Standards PRC-002-5 and PRC-028-1, as those dates have been well vented across industry. As that project has proposed for some Generator Owners, this can be as much as within three (3) calendar years of the standard's effective date for 50% of those Generator Owners' BES Inverter□Based Resources. Then the rest of their BES Inverter□Based Resources must be compliant by January 1, 2030. The SDT Project 2021-04 SDT made similar simplifications for other Generator Owners with future IBRs yet to commission and for Category 2 Generator Owners. 2. We point out a misspelling of the work "ride-through" within the first paragraph of the Background Section of the Implementation Plan. 3. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3	

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	
Document Name	

Comment

- AES CE is concerned by the language in several Measures reading "Each Generator Owner and Transmission Owner have **evidence of actual disturbance monitoring**…". There will be many plants that do not experience an applicable disturbance before this Standard becomes effective and therefore cannot demonstrate adherence to ride-through requirements as prescribed. We are also concerned about expectations for this Measure as time goes on, are we expected to document and record every applicable disturbance and the asset's performance? Setting up monitoring/tracking/retention for this portion of the Measures is a huge additional burden that will be ongoing unless clarification is provided.
- OEMs have not been forthcoming with operating limit data/equipment trip capabilities, and will not comment on or approve alternative proposed settings without a significant amount of studies and simulations from the GO first. Due to the lack of information from OEMs, we are concerned that the exemption process in R4 will be impossible to meet within the 12 month timeframe for larger GOs.
- Quality EMT models including all equipment information needed are not available for legacy equipment (inverters, PPCs). Many legacy inverters do not have an EMT model, and those that do have models are not adequately validated against equipment performance. Creation of models is either not supported or can be developed at very high cost. Models created after the inverters were initially released are of inadequate quality because the equipment is no longer able to be in a lab environment.
- To consider this, AESCE suggests that the SDT include exceptions for legacy equipment where the performance may not be predictable specifically due to a lack of modeling or inverter information.

Likes 0	
Dislikes 0	

Response

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1

Answer	
Document Name	

Comment

TAL understands that the committee was following previous precedent of the 20MVA or greater facilities; however, we believe this standard will create undue hardship on utilities who will be required to meet this standard. 20MVA seems like a low threshold for the size of IBRs. TAL believes the impact of IBRs as small as 20 MVA seems minimal to the integrity of the BES.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	
Comment	

The NAGF has no additional comments.

Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5

Answer	
Document Name	
Comment	

Constellation has no additional comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	
Comment	

Section 4: Applicability:

4.2 is not aligned with the PRC-028. The DT should consider the alignment of the applicability section between all IBR standards.

1) It is not clear to me what “The Elements associated with...” means in 4.2.1. Does it mean power system elements?

R2 The new wording in Section 2.1.3 is unclear.

MRO NSRF recommends it be changed to “Prioritize Real Power or Reactive Power delivery when the voltage is less than 0.95 per unit, the voltage is within the continuous operating region, and the IBR cannot deliver both Real Power and Reactive Power due to a current limit or Reactive Power limit unless otherwise specified through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.”

R3 The MRO NSRF is still concerned with the lack of provisions for exemptions for frequency limitation (RoCof) that may put some of the legacy IBR in a non-compliant state and may require a costly upgrade to meet R3 requirements.

MRO NSRF Recommends the adoption of a frequency ride requirement for legacy equipment be delayed until Generator Owners can properly evaluate the capability of legacy equipment.

R4 The CEA is not a defined NERC term in the Glossary of Terms Used in NERC standard list, MRO NSRF recommends spelling out Compliance Enforcement Authority (CEA) in Requirement R4 subpart 4.2 since it is the first time seeing that term in the requirement language.

Attachment #1

MRO NSRF agrees with removing the previous figures 1 and 2 from attachment # 1 but we recommend adding at least three voltage waveform examples into TR to illustrate how the Table 1 and 2 should be used to determine the compliance with voltage ride through

TR More information should be added to some frequency waveform examples in TR to illustrate how to calculate the RoCoF.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5

Answer	
Document Name	2020-02_Unoffical_Comment_Form_07222024(HQ).docx

Comment

see attached file

Likes 0	
Dislikes 0	

Response

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	
Document Name	
Comment	

R3 refers to “must Ride-through zone” but Attachment 2 does not identify what this zone is.

Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6

Answer	
Document Name	
Comment	

Constellation has no additional comments.

Kimberly Turco on behalf of Constellation Energy Segments 5 and 6.

Likes 0	
Dislikes 0	
Response	

Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3

Answer	
Document Name	
Comment	

Madison Gas and Electric supports the comments of the MRO NSRF.

Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	

Document Name	
Comment	
MP agrees with MRO’s NERC Standards Review Forum’s (NSRF) additional comments.	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Greg Sorenson	
Answer	
Document Name	
Comment	
RF appreciates the improvements made in this version.	
Likes 0	
Dislikes 0	
Response	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	EEI Near Final Draft Comments _ Project 2020-02 PRC-029 Draft 3 _ Rev 0f __ 8_09_2024.docx
Comment	
See comments submitted by the Edison Eclectic Institute in the attached file.	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See EEI Comments	

Likes 0	
Dislikes 0	

Response

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI offers the following additional comments on the proposed 3rd draft of PRC-029-1:

- EEI does not support the inclusion of the phrase “The Elements associated with” as contained in the Facilities Section (4.2.1). The inclusion of this phrase expands the scope in ways that are unclear creating unnecessary compliance confusion.
- Bullet 1 under Requirement R1 is unnecessary and should be deleted, noting that facilities are never obligated to stay connected to a fault.
- EEI asks that the DT provide additional clarity to Requirement R4, subpart 4.2.2 noting that there is insufficient clarity regarding what is needed to support a hardware limitation and what the deadline is for the submission of a limitation.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

LG&E/KU greatly appreciates the SDT's work and is providing feedback with the intent of providing helpful input that will assist in creating a clearer and more consistent standard to meet the FERC directives. We acknowledge the large number of comments provided and thank the drafting team for their work on this standard. A summary of our most substantive feedback is below:

1. Change R1 to apply to voltage and frequency Ride-through (and renumber R1 -> R3, R2 -> R1, and R3 -> R2).
2. Remove footnote 3 or, at minimum, clarify that current blocking is allowed only if not prohibited by the associated functional entities.
3. Ensure M1 addresses all of the exemptions in R1.
4. Replace "Reactive Power limit" with "apparent power limit" in R2 Part 2.1.3, and restore the "according to the requirements …" language.
5. R2 Part 2.3 should clarify that current blocking is acceptable only if not prohibited by the associated functional entities.
6. All mentions of continuous, mandatory, and/or permissive operating regions should include a reference to Attachment 1 (e.g., "specified in Attachment 1") since these terms are no longer defined terms.
7. Move R4 Part 4.2.2 up a level (i.e., 4.2.2 -> 4.3, 4.3 -> 4.4) and include a timeline for the GO to notify the associated functional entities after it has received an acceptance or rejection of its hardware limitation.
8. Modify items 1 and 2 in Attachment 1 to better address hybrid plants.
9. Remove the second sentence of item 7 in Attachment 1.
10. Add an item in Attachment 1 defining "deviation".
11. Add an item in Attachment 1 permitting IBRs to trip for consecutive voltage deviations subject to the requirements of the associated functional entities.
12. Add an item in Attachment 2, "Table 3 is only applicable when the voltage is within the "must Ride-through zone" as specified in Attachment 1."
13. Modify Table 3 to match IEEE 2800 requirements.
14. Remove Figure 1.
15. In locations where alternative performance requirements are discussed, either add Transmission Owner to the list of entities or replace the list (TP, PC, RC, or TOP) with "the associated functional entities". It is the TO that is responsible for establishing and evaluating interconnection requirements for interconnecting generation Facilities (FAC-001/002).

Likes 0	
Dislikes 0	

Response

Nick Leathers - Ameren - Ameren Services - 3 - SERC

Answer	
Document Name	

Comment

Ameren does not have any additional comments for consideration by the drafting team.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	
Document Name	

Comment	
Each requirement contains statement *"…shall **ensure** the design and operation is such that …"*. The statement has no quantitative meaning nor direct requirements. Let's take R2.2. or R2.3. for example: Assuming SDT members own and operate IBRs, please explain WHAT YOU WILL DO to comply with R2.2. and R2.3. WEC Energy Group requests that the Implementation Guidance document be created and published to help industry better understand this convoluted and unclear standard and how to implement it. Following is an example of a standard being unclear: *R2. "Each Generator Owner shall ensure the design and operation is such that the voltage performance for each IBR adheres to the following during a voltage excursion, unless a documented hardware limitation exists in accordance with Requirement R4."* What is defined as "voltage excursion"? Is it the voltage outside the region identified in Attachment 1, or is it something else? Further, R2.1. goes on to state: "*While the voltage at the high-side of the main power transformer remains within the continuous operation region as specified in Attachment 1, each IBR shall..".* If the voltage remains within the "continuous operating region", how is that a "voltage excursion".	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	
Document Name	
Comment	
In our entity's review of this project, we are voting in the affirmative. We understand and appreciate that this project addresses important considerations for reliability and security responsiveness. However, we also recognize that this project in its current form presents compliance and performance risks that remain unresolved. While affirmatively supporting this project to address the immediate regulatory assignments tied to FERC Order 901, NERC and the ERO must continue a constructive dialog with industry beyond this vote to truly optimize the impacts of this project on reliability, sustainability, and affordability. We encourage NERC to permit extending the SDT team and project to offer prospective enhancements or revisions to satisfy these compliance and performance risks.	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	
Document Name	
Comment	

PNM agrees with the comments made by EEI.

Likes 0	
Dislikes 0	

Response

Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	2020-02_EPRI Comments on Draft 3 of NERC PRC-029 (IBR ride-through) Reliability Standard.pdf

Comment

I. Introduction

1. The Electric Power Research Institute (EPRI)[1] respectfully submits these comments (This Response) in response to North American Electric Reliability Corporation (NERC)'s request for formal comment on Project 2020-02 Modifications to PRC-024 (Generator Ride-through), issued on July 22, 2024.

2. EPRI closely collaborates with its members inclusive of electric power utilities, Independent System Operators (ISOs), and Regional Transmission Organizations (RTOs), as well as numerous other stakeholders, domestically and internationally. In its role, EPRI conducts independent research and development relating to the generation, delivery, and use of electricity for public benefit by working to help make electricity more reliable, affordable and environmentally safe. EPRI's comments on this topic are technical in nature based upon EPRI's research, development, and demonstration experience over the last 50 years in planning, analyzing, and developing technologies for electric power.

3. EPRI research and technology transfer deliverables are generally accessible on its website to the public, either for free or for purchase, and occasionally subject to licensing, export control, and other requirements.[2] The publicly available and free-of-charge milestone reports from a U.S. Department of Energy (DOE)- and EPRI member-funded research project, Adaptive Protection and Validated Models to Enable Deployment of High Penetrations of Solar PV ("PV-MOD"), [3] and other research deliverables substantiate many of the comments made in This Response.

4. While not a standards development organization (SDO), EPRI conducts research and demonstration projects in relevant areas as well as facilitates knowledge transfer and collaboration that SDOs may, at times, use to inform technical and regulatory standards development, such as in Institute of Electrical and Electronics Engineers (IEEE), International Electrotechnical Commission (IEC), International Council on Large Electric Systems (CIGRE), and NERC.[4]

5. EPRI's comments in This Response address reliability and NERC's draft PRC-029 Reliability Standards for IBRs ride-through requirements developed under project 2020-02. All comments are aimed at providing independent technical information to respond to the draft published by NERC based on EPRI's research and development results and associated staff expertise and do not necessarily reflect the opinions of those supporting and working with EPRI to conduct collaborative research and development. Where appropriate, EPRI's comments do not only address the specific questions of the NOPR but also related scope that may help to inform a final order. Some of EPRI's comments presented in This Response have also been submitted in response to the previous Federal Energy Regulatory Commission's (FERC) Notice of Proposed Rulemaking (NOPR) to direct North American Electric Reliability Corporation (NERC) to develop Reliability Standards for inverter-based resources (IBRs) that cover data sharing, model validation, planning and operational studies, and performance requirements (RM22-12), issued on November 17, 2022.

6. EPRI also submitted comments on the initial draft of PRC-029 which was issued on March 27, 2024, and on Draft 2 which was issued June 18, 2024. This 3rd set of EPRI comments supports the same direction as the previously submitted comments and offers a technical analysis based on the latest "Draft 3".[5]

II. Conclusion

7. EPRI appreciates the opportunity to provide NERC with its technical recommendations and comments on these important topics related to Reliability Standards for IBRs. EPRI looks forward to working with its members, NERC, and other stakeholders on providing further independent technical information on these important questions.

III. Contact Information

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Manish Patel, Technical Executive

Anish Gaikwad, Deputy Director

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[1] EPRI is a nonprofit corporation organized under the laws of the District of Columbia Nonprofit Corporation Act and recognized as a tax-exempt organization under Section 501(c)(3) of the U.S. Internal Revenue Code of 1996, as amended, and acts in furtherance of its public benefit mission. EPRI was established in 1972 and has principal offices and laboratories located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass. EPRI conducts research and development relating to the generation, delivery, and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety, and the environment. EPRI also provides technology, policy and economic analyses to inform long-range research and development planning, as well as supports research in emerging technologies.

[2] https://www.epri.com (last accessed, August 6, 2024)

[3] PV-MOD Project Website. EPRI. Palo Alto, CA: 2024. [Online] https://www.epri.com/pvmod (last accessed, August 6, 2024)

[4] For transparency, we would like to disclose that EPRI collaborates with other organizations such as IEEE, IEC, CIGRE, and NERC; however, EPRI is not a regulatory- or standard-setting organization. EPRI research is often considered in the development of recommendations, guidelines, and best practices that are not determinative.

[5] https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	
Document Name	

Comment

OPG supports NPCC Regional Standards Committee’s comments.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	
Document Name	

Comment

NPCC RSC supports the project.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	
Document Name	

Comment

We concur with EEI's comments.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

Southern Company received the following feedback from one of our OEM providers relating to the Frequency Ride-Through requirements in PRC-029:

“...confirms that **neither** its legacy nor new turbines can meet the proposed frequency ride-through requirements. Wind turbines contain hundreds of electromechanical devices that must be redesigned and tested before any new stringent frequency ride-through zones can be confirmed."

"...is currently designing and evaluating our turbines' capabilities according to **IEEE 2800** standards. Consequently, any new requirements deviating from IEEE 2800 will be unfeasible in the near term.”

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	
Document Name	

Comment

Invenergy thanks the drafting team for the opportunity to provide the above comments.

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5

Answer	
Document Name	

Comment

Invenergy thanks the drafting team for the opportunity to provide the above comments.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators

Answer	
Document Name	

Comment

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

George E Brown - Pattern Operators LP - 5

Answer	
Document Name	

Comment

Pattern Energy supports Edison Electric Institute’s and Grid Strategies LLC’s comments.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	
Document Name	

Comment

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,Texas RE,NPCC,SERC,RF, Group Name SRC 2024	
Answer	
Document Name	
Comment	
In the previous posting, the SRC provided this comment which was not addressed in the current version for comment and ballot: Attachment 1 lists a minimum ride-through time of 1800 seconds for the continuous operation voltage region between 1.05 pu and 1.1 pu (<= 1.1 and >1.05) in Tables 1 and 2. The SRC requests that, consistent with IEEE 2800, an exception for 500 kV systems be allowed such that the minimum ride-through time for 1.05 pu < voltage <= 1.1 pu for 500 kV systems is “Continuous,” because the 1.05 pu < voltage <= 1.1 pu voltage range is within the normal operation range for some systems, such as PJM’s system. The SRC again requests the exception for 500KV systems be incorporated. The SDT has not explainedwhy this difference from the IEEE 2800 is appropriate for 500 KV reliability. We recommend the M1 references to Sequence Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder be adjusted to lower case terms, as these are not defined in the Glossary of Terms. PRC 28 utilizes acronyms for these that may be appropriate for this standard. Similarly a change was made in R4 to replace Regional Entity with CEA, which is an undefined term and acronym in the Glossary. Suggest spelling this out and considering defining or pointing to the Rules of Procedure.	
Likes 0	
Dislikes 0	
Response	
Srinivas Kappagantula - Arevon Energy - 5	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
MISO understands the increased need for Ride-through capabilities as system inertia decreases. We also see challenges for equipment to demonstrate compatibility with the frequency requirements (Attachment 2) which go beyond industry standards (IEEE 2800) and MISO's current Tariff requirements. MISO's plan for conformity currently relies on IEEE P2800.2 and we are planning to use that as the basis for testing to ensure IBRs meet MISO Tariff requirements. We ask that consideration be given to aligning PRC-029 with other existing industry standards.	
Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
Regarding the Implementation Plan. Six months after FERC approval is unreasonable to have equipment and procedures in place and changes made. Especially considering several entities will need to order and install new monitoring equipment from most likely the same companies. This implementation plan should be the same as PRC-28. NCPA understands Ferc Order 901. The SDT has not provided any cost or expected reliability indices improvement estimates. Consequently, it is impossible for entities to determine if this proposal is cost effective to address recommendations of FERC order 901 or if, or to what extent, this proposal will improve reliability. Reliability standards should not be added or changed until the SDT provides said information so that Registered Entities can make educated determinations related to the cost and benefits of reliability standard modifications or new proposals. The SDT has not provide a cost or tangible reliability benefit estimate. Thus we are unable to analyze the cost and reliability benefits this proposal would provide without any data. And, ironically GO/GOP IBR Entities are being asked to spend money to procure and install a bunch of devices to record data and/or to perform new activities that may, or may not, improve reliability. And if they do improve reliability, we don't have any idea if the reliability benefits are worth the cost. Electricity customers' rates would need to be raised and there is no justification or hard evidence related to the improved reliability increase magnitude; i.e. no cost/benefit justification to provide electricity customers as to why their rates are increasing.	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	

WECC believes that PRC-029 does a good job being consistent on use of IBR (and PRC-028 and PRC-030 DTs should take note on consistency.) Note that the redlined version of the posted Standard did not capitalize “reactive power” in M2 but the clean version did. Another example is Footnote 11 in the redline version used “active power” but clean version was changed to “Real Power”. DT could receive responses based on either document and needs to ensure consistency in the clean version or note the differences.

WECC suggests that Requirement 4 could be removed and listed as actions to be done within the Implementation Plan. From an auditing perspective, noncompliance is based on administrative issues (failure to provide in 12 months) and is only applicable to units already “in-service” as of the effective date. “In-service” is meant to be exactly what? (WECC has an applicable temr in the NERC Glossary, but that is only appliable in the Western Interconnection. Different entites may have a differend definition of "in-service." Suggest a defintion be developed.) First synch date the IBR is “in-service”. Reliability issues can happen with units not at the COD date and this issue should not be ignored or exacerbated by assuming, if that is the case, that “in-service” equated to COD. There will be discussions as to what the effective date is (for R4 specifically) due to the Implementation Plan dependence provided by the DT. This again calls for a timeline to be provided for each Standard being considered especially for these IBR-related Standards as the IPs are not clearly defined. Still not clear why CEAs need notification of hardware limitations within a Standard. A onetime Alert for R4 may be appropriate followed up by a Periodic Data Submittal when hardware issues are alleviated (currently no response to CEA is required which begs the question why inform them in the first place?). Severe VSL needs to remove CEA as a result of not being in the section for responses required.

VSLs for R3 need to be adjusted to use “IBR” versus “facility”. VSLs for R4 indicated a basis of effective date of R4 versus effective date of Standard as the language of the Standard states. This needs corrected as those dates may be different. Another clear reason to provide a timeline diagram of Implementation Plan dates.

Attachment 2 Bullet 1 for Voltage- Is the “that include wind” limited to type 3 and type 4 for the hybrid aspect?

Attachment 2 Bullet 4 for frequency—Need to replace “facility” with IBR.

PRC-029 Implementation Plan Requirement 4 “Non-BES IBRs”- Need to change “or” to “for” in the sentence describing R4’s timeline for implementation. Bottom of page 5 capitalize “ride-through”.

All BES IBRs, including those that have repeatedly failed from a performance perspective, default to the PRC-028 timeline which employs an extended timeframe for phased-in implementation.

PRC-029 Implementation Plan- Separating the Requirements compliance obligation timeframe out by design and operation is not realistic and gives the false appearance of being partially applicable prior to Jan 1, 2030. The language of the Requirements, as written, will be contested by entities as the language requires both the “design and operation” for BES IBRs and non-BES IBRs. Effectively a review of the design will be an administrative effort for an item that could be designed today but there is no quality or accuracy language for the design aspects. The proof that design was completed in an effective manner to mitigate the risk can only be determined if an event occurs. R4 has additional implementation time built into the Requirement language which provides a false appearance of being applicable on the effective date of the Standard.

Likes 0	
Dislikes 0	
Response	

Jennifer Neville - Western Area Power Administration - 1,6	
Answer	

Document Name	
Comment	

Section 4: Applicability:

{C}4.2 {C}is not aligned with the PRC-028. The DT should consider the alignment of the applicability section between all IBR standards.

{C}1)   It is not clear to me what “The Elements associated with...” means in 4.2.1. Does it mean power system elements?

R2   The new wording in Section 2.1.3 is unclear.

MRO NSRF recommends it be changed to “Prioritize Real Power or Reactive Power delivery when the voltage is less than 0.95 per unit, the voltage is within the continuous operating region, and the IBR cannot deliver both Real Power and Reactive Power due to a current limit or Reactive Power limit unless otherwise specified through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.”

R3   The MRO NSRF is still concerned with the lack of provisions for exemptions for frequency limitation (RoCof) that may put some of the legacy IBR in a non-compliant state and may require a costly upgrade to meet R3 requirements.

MRO NSRF Recommends the adoption of a frequency ride requirement for legacy equipment be delayed until Generator Owners can properly evaluate the capability of legacy equipment.

R4   The CEA is not a defined NERC term in the Glossary of Terms Used in NERC standard list, MRO NSRF recommends spelling out Compliance Enforcement Authority (CEA) in Requirement R4 subpart 4.2 since it is the first time seeing that term in the requirement language.

Attachment #1

MRO NSRF agrees with removing the previous figures 1 and 2 from attachment # 1 but we recommend adding at least three voltage waveform examples into TR to illustrate how the Table 1 and 2 should be used to determine the compliance with voltage ride through

TR   More information should be added to some frequency waveform examples in TR to illustrate how to calculate the RoCoF.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own. In addition, ERCOT encourages NERC to consider defining the averaging window for Rate of Change of Frequency, as leaving the averaging window open ended will result in measurement inconsistencies in protection systems and post-event analysis.	
Likes 0	
Dislikes 0	
Response	
Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

Elevate continues to strongly encourage NERC to reconsider adoption of IEEE 2800-2022. The unwillingness to adopt IEEE 2800-2022 by NERC is leading to entirely duplicative efforts that are not serving any additional value as compared to the work conducted in the IEEE 2800-2022 developments. It does not appear that a holistic approach and strategy is being taken to meet the FERC Order No. 901 directives, which is leading to very low ballot scores, significant rework, and misalignment with industry recommended practices.

The draft NERC PRC-029 is duplicative with IEEE 2800-2022 Clause 7 yet only covers a small fraction of the IBR-specific capability/performance requirements and necessary equipment limitation details that are outlined in that clause. Therefore, there is no clear reliability benefit versus the cost of implementation PRC-029 as compared with IEEE 2800-2022 and the recommendations set forth in the NERC disturbance reports and guidelines. There are three core items that should be addressed in the draft NERC PRC-029 standard:

- Requirement R4 of the standard be updated to include frequency ride-through criteria exemptions for IBRs in-service by the effective date of the standard that have known hardware limitations.
- The draft PRC-029 standard should align the FRT curve with the IEEE 2800 standard's FRT curve
- If necessary, the "maximization" concept could be introduced to maximize the capabilities of legacy IBRs to the available software/firmware/setting limits.

Elevate strongly recommends a single NERC standard that adopts IEEE 2800-2022 in a uniform and consistent manner. NERC can also issue a reliability guideline or implementation guidance that supports industry implementation of the standard. Rather than recreate parts of IEEE 2800-2022 inconsistently over multiple different standards, Elevate recommends a singular standard for BPS-connected IBR capability and performance requirements related to IEEE 2800-2022. Additional NERC standards can be developed where needed in situations where they are not covered directly with IEEE 2800-2022 (e.g., NERC PRC-030).

Concerns with Draft PRC-029

If the draft PRC-029 standard is to be pursued as currently structured, Elevate would like to highlight the following concerns:

· **Inconsistencies with PRC-029 and IEEE 2800-2022:** There are numerous inconsistencies in the draft standard language and attachment 1 and 2 when compared to IEEE 2800-2022. These should be considered and reviewed for clarity and completeness in the standard.

- IEEE 2800 recognizes FRT requirement limitations, but the standard does not
- IEEE 2800 recognizes limitations with VSC-HVDC equipment in meeting consecutive votlage deviation ride-through capabilite, the PRC-029 standard does not.
- IEEE 2800 allows for an exception for "self-protection" when negative-sequence voltage is greater than specified duration and threshold, which may be required for Type III WTG based plants. PRC-029 does not have this exception.
- IEEE 2800 recognizes 500kV system voltages are actually operated in the range of 525kV and therefore has equipment rated to 550kV. These 500kV operating conditions and corresponding updated voltage ride-through curves should be considered in the standard.
- In IEEE 2800 the frequency ride-through criteria defines 10-minute time periods for the cumulative specifications of FRT, whereas the standard defines them in a 15 minute time period (Table 3 of Attachment 2). This should be clarified and identified.
- IEEE 2800 has an exception on IBR post-disturbance current limitations for voltage disturbances that reduce RPA voltage to less than 50% of nominal, but the standard does not have this exception.
- A ride-through duration of 1800 seconds is specified in both IEEE 2800 and draft PRC-029 for V > 1.05 and ≤ 1.10. PRC-029 is silent on the cumulative time period for this requirement, whereas IEEE 2800-2022 specifies that this is cumulative over a 3600 second time period.
- Attachment 2: frequency ride-through criteria should be updated to fully match with IEEE 2800. Creating a different FRT ride-through curve without adequate technical justification will continue to challenge the industry.
- The standard should be updated to explicitly state that the voltage ride-through curves are to be interpreted as voltage vs time duration as is stated in IEEE 2800. This is to ensure that there is no incorrect interpretation that these curves are "envelope" curves. This could be done by adding a new note to explicitly call out the voltage vs time duration interpretation of the curves.

Likes 0	
Dislikes 0	

Response

Bill Zuretti - Electric Power Supply Association - 5

Answer	
Document Name	EPSA FINAL Comments on IBR Standards .pdf
Comment	
Likes 0	
Dislikes 0	
Response	

Consideration of Comments

Project Name:	2020-02 Modifications to PRC-024 (Generator Ride-through) | PRC-029-1
Comment Period Start Date:	7/22/2024
Comment Period End Date:	8/12/2024
Associated Ballot(s):	2020-02 Modifications to PRC-024 (Generator Ride-through) Implementation Plan AB 3 OT 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-029-1 AB 3 ST

There were 70 sets of responses, including comments from approximately 159 different people from approximately 112 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, contact Manager of Standards Information, Nasheema Santos (via email) or at (404) 290-6796.

Questions

1. Do you agree with the proposed definition of Ride-through? If not, please state what revision would be acceptable and why.

2. Do you agree with the changes made in this draft of PRC-029-1?

3. Provide any additional comments for the Drafting Team to consider, if desired.

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO

					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities- Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	MRO,NPCC,RF,SERC,SPP RE,Texas RE,WECC	SRC 2024	Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	1	WECC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Greg Campoli	NYISO	1	NPCC

					Elizabeth Davis	PJM	2	RF
					Matt Goldberg	ISO New England	2	NPCC
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NPCC,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Jolly Hayden	East Texas Electric Cooperative, Inc.	NA - Not Applicable	Texas RE
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC

					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern	6	SERC

						Company Generation		
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Micah Runner	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC

					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					David Kwan	Ontario Power Generation	4	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Sean Cavote	PSEG	4	NPCC

					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC
					Erin Wilson	NB Power	1	NPCC
					James Grant	NYISO	2	NPCC
					Michael Couchesne	ISO-NE	2	NPCC
					Kurtis Chong	IESO	2	NPCC

					Michele Pagano	Con Edison	4	NPCC
					Bendong Sun	Bruce Power	4	NPCC
					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Victoria Crider	Dominion Energy	3	NA - Not Applicable
					Sean Bodkin	Dominion Energy	6	NA - Not Applicable
					Steven Belle	Dominion Energy	1	NA - Not Applicable
					Barbara Marion	Dominion Energy	5	NA - Not Applicable
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC

					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

1. Do you agree with the proposed definition of Ride-through? If not, please state what revision would be acceptable and why.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports the comments provided by the NAGF which state: a. Recommend removing the word "entire" and the phase "in its entirety" from the proposed definition; b. adding the following revised language"…and continuing to operate through System Disturbances as defined in the applicable Reliaiblity Standards."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The Standards Committee, with advisement from NERC, the 2020-02 Drafting Team, and leveraging the results of the September 4-5 Technical Conference on Ride-through have incorporated industry suggestions concerning the definition for "Ride-through". The resulting definition removes language that has been identified as either ambiguous or appears to specify performance requirements for how an IBR should recover following a grid disturbance. The definition now reads as: "The plant/facility remains connected and continues to operate through voltage or frequency system disturbances."	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy agrees with and supports the following NAGF comment:	

The NAGF does not agree with the proposed definition of Ride-through and provides the following recommendations for consideration: a. Recommend removing the word "entire" and the phrase "in its entirety" from the proposed definition. b. Recommend adding the following revised language "…and continuing to operate through System Disturbances as defined in the applicable Reliability Standards."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The Standards Committee, with advisement from NERC, the 2020-02 Drafting Team, and leveraging the results of the September 4-5 Technical Conference on Ride-through have incorporated industry suggestions concerning the definition for "Ride-through". The resulting definition removes language that has been identified as either ambiguous or appears to specify performance requirements for how an IBR should recover following a Grid Disturbance. The definition now reads as: The plant/facility remains connected and continues to operate through voltage or frequency system disturbances.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
See EEi comments	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the response to EEI.	
Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable	

Answer	No
Document Name	
Comment	

1. We believe the addition of "in its entirety" is ambiguous and misplaced within the proposed definition. We propose the phrase should be moved to the end to imply the entire time duration of a Disturbance, from the start of the Disturbance to its return to pre-disturbance conditions.

2. We believe the addition of the term "System" should be removed from the definition. According to the NERC Glossary of Terms, the term is defined as "a combination of generation, transmission, and distribution components." This proposed Reliability Standard only applies to Generator Owners, an entity that would not possess transmission and distribution asset components.

3. We believe the reference to the term "Disturbance" within the definition is too vague by itself. The proposed title of this Reliability Standard is "Frequency and Voltage Ride-through Requirements for Inverter-Based Resources." The proposed purpose of this Reliability Standard is "to ensure that [Inverter-Based Resources] IBRs Ride-through to support the Bulk Power System (BPS) during and after defined frequency and voltage excursions." Both imply any definition used in reference to this Reliability Standard should be narrowed to unplanned Frequency and Voltage events that produce abnormal system conditions or deviations to the electric system, as derived from term's definition listed within the NERC Glossary of Terms. Therefore, we propose ending the "Ride-through" definition with the phrase "through the duration of a frequency or voltage Disturbance in its entirety, from its start to the return to pre-disturbance conditions."

Likes 0	
Dislikes 0	
Response	

Thank you for your comment.
The Standards Committee, with advisement from NERC, the 2020-02 Drafting Team, and leveraging the results of the September 4-5 Technical Conference on Ride-through have incorporated industry suggestions concerning the definition for "Ride-through". The resulting definition removes language that has been identified as either ambiguous or appears to specify performance requirements for how an IBR should recover following a grid disturbance. Similarly, "system" and "disturbance" are now lowercase terms. The definition now reads as: "The plant/facility remains connected and continues to operate through voltage or frequency system disturbances."

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

The NAGF does not agree with the proposed definition of Ride-through and provides the following recommendations for consideration:

a. Recommend removing the word "entire" and the phrase "in its entirety" from the proposed definition.

b. Recommend adding the following revised language "…and continuing to operate through System Disturbances as defined in the applicable Reliability Standards."

Likes 0	
Dislikes 0	
Response	

Thank you for your comment.
The Standards Committee, with advisement from NERC, the 2020-02 Drafting Team, and leveraging the results of the September 4-5 Technical Conference on Ride-through have incorporated industry suggestions concerning the definition for "Ride-through". The resulting definition removes language that has been identified as either ambiguous or appears to specify performance requirements for how an IBR should recover following a grid disturbance. Similarly, "system" and "disturbance" are now lowercase terms. The definition now reads as: "The plant/facility remains connected and continues to operate through voltage or frequency system disturbances."

Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	

Constellation aligns with NAGF comments. Legacy inverters will not be able to ride through voltage and frequency events. It’s important to include exemption for legacy inverters. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Capital Power supports the NAGF's comments: *The NAGF does not agree with the proposed definition of Ride-through and provides the following recommendations for consideration:* *a. Recommend removing the word “entire” and the phrase “in its entirety” from the proposed definition.* *b. Recommend adding the following revised language “…and continuing to operate through System Disturbances as defined in the applicable Reliability Standards.”*	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

The Standards Committee, with advisement from NERC, the 2020-02 Drafting Team, and leveraging the results of the September 4-5 Technical Conference on Ride-through have incorporated industry suggestions concerning the definition for "Ride-through". The resulting definition removes language that has been identified as either ambiguous or appears to specify performance requirements for how an IBR should recover following a grid disturbance. Similarly, "system" and "disturbance" are now lowercase terms. The definition now reads as: "The plant/facility remains connected and continues to operate through voltage or frequency system disturbances."

Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
NextEra believes that the definition of ride-through is too broad and does not directly tie back to voltage or frequency requirements. The word "entire" leaves too much room for interpretation of single IBR unit driving an unnecessary investigation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The Standards Committee, with advisement from NERC, the 2020-02 Drafting Team, and leveraging the results of the September 4-5 Technical Conference on Ride-through have incorporated industry suggestions concerning the definition for "Ride-through". The resulting definition removes language that has been identified as either ambiguous or appears to specify performance requirements for how an IBR should recover following a grid disturbance. Similarly, "system" and "disturbance" are now lowercase terms. The definition now reads as: "The plant/facility remains connected and continues to operate through voltage or frequency system disturbances."	

Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	

Constellation aligns with NAGF comments. Legacy inverters will not be able to ride through voltage and frequency events. It's important to include exemption for legacy inverters.

Kimberly Turco on behalf of Constellation Energy Segments 5 and 6.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment

Minnesota Power (hereafter MP) agrees with EEI that the "ride-through" definition was clearer as proposed in IEEE 2800-2022.

Likes 0	
Dislikes 0	

Response

Thank you, please see the response to EEI.

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	No
Document Name	
Comment	
LG&E/KU agrees with EEI; there is no reason to deviate from the definition included in IEEE Std 2800-2022 and IEEE Std 1547-2018: "Ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified." This definition makes it more clear that there are "limits" to Ride-through. The definition proposed by the DT implies that *any* tripping is failed Ride-through, even if the trip occurs for a condition where it is acceptable. Include the IEEE definition verbatim, there is no need for modification.	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the response to EEI.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
"Please see EEI Comments"	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the response to EEI.	

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of the NAGF for Question 1.	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the response to EEI.	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Request clarification on the meaning of "in its entirety" and its intended purpose. Its inclusion adds confusion as the beginning of the definition already states "the entire plant/facility". Does "in its entirety" apply to the entire facility, or the entire disturbance event? Recommend "Ride-through: The entire plant/facility remaining connected to the Bulk Power System and continuing to operate through System Disturbances."	
Likes 0	
Dislikes 0	

Response	
The Standards Committee, with advisement from NERC, the 2020-02 Drafting Team, and leveraging the results of the September 4-5 Technical Conference on Ride-through have incorporated industry suggestions concerning the definition for “Ride-through”. The resulting definition removes language that has been identified as either ambiguous or appears to specify performance requirements for how an IBR should recover following a grid disturbance. Similarly, “system” and “disturbance” are now lowercase terms. The definition now reads as: “The plant/facility remains connected and continues to operate through voltage or frequency system disturbances.”	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
NIPSCO believes that the definition of ride-through is too broad and does not directly tie back to voltage or frequency requirements. The word “entire” leaves too much room for interpretation of single IBR unit driving an unnecessary investigation.	
Likes 0	
Dislikes 0	
Response	
The Standards Committee, with advisement from NERC, the 2020-02 Drafting Team, and leveraging the results of the September 4-5 Technical Conference on Ride-through have incorporated industry suggestions concerning the definition for “Ride-through”. The resulting definition removes language that has been identified as either ambiguous or appears to specify performance requirements for how an IBR should recover following a grid disturbance. Similarly, “system” and “disturbance” are now lowercase terms. The definition now reads as: “The plant/facility remains connected and continues to operate through voltage or frequency system disturbances.”	
Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	

Answer	No
Document Name	
Comment	
B. Ride-through definition · Consider adopting definition from IEEE 2800, which is from IEEE 1547, and well understood by the industry.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	
Invenergy recommends removing “entire” and “in its entirety” from the proposed definition. As written, the definition attempts to prescribe an unreasonable interpretation of what ride-through should be from a system reliability perspective.	
Likes 0	
Dislikes 0	
Response	
The Standards Committee, with advisement from NERC, the 2020-02 Drafting Team, and leveraging the results of the September 4-5 Technical Conference on Ride-through have incorporated industry suggestions concerning the definition for “Ride-through”. The resulting	

definition removes language that has been identified as either ambiguous or appears to specify performance requirements for how an IBR should recover following a grid disturbance. Similarly, “system” and “disturbance” are now lowercase terms. The definition now reads as: “The plant/facility remains connected and continues to operate through voltage or frequency system disturbances.”

Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	

Invenergy recommends removing “entire” and “in its entirety” from the proposed definition. As written, the definition attempts to prescribe an unreasonable interpretation of what ride-through should be from a system reliability perspective.

Likes 0	
Dislikes 0	
Response	

The Standards Committee, with advisement from NERC, the 2020-02 Drafting Team, and leveraging the results of the September 4-5 Technical Conference on Ride-through have incorporated industry suggestions concerning the definition for “Ride-through”. The resulting definition removes language that has been identified as either ambiguous or appears to specify performance requirements for how an IBR should recover following a grid disturbance. Similarly, “system” and “disturbance” are now lowercase terms. The definition now reads as: “The plant/facility remains connected and continues to operate through voltage or frequency system disturbances.”

George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	

Pattern Energy does not believe it is necessary to add a glossary term for Ride-Through. Ride-through is an operational requirement that is defined by a set of magintudes and should remain defined within the requirements of the NERC Relaibility Standards, as traditionaly done.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The term is also used to bridge the PRC-029 standard with “Ride-through criteria” used in PRC-030.	
Srinivas Kappagantula - Arevon Energy - 5	
Answer	No
Document Name	
Comment	
Please refer to NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the response to NAGF.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

MISO supports the comments of the ISO/RTO Council (IRC) Standards Review Committee (SRC). In addition, we believe it is important to get the wording of the Ride-through definition accurate and clear. If the language is not clear (as to what is allowed/disallowed), it will likely lead to future disagreements. One possible solution is to add the words "as specified" to the **Ride-through** definition to more explicitly tie the definition to the requirements under the proposed PRC-029 standard as shown below. **Ride-through:** The entire plant/facility remaining connected to the Bulk Power System, and continuing in its entirety to operate as specified through the time-frame of System Disturbances. This is only one possible approach to better capture the intent of the standard as described in the below excerpt from the **PRC-029-1 Technical Rationale, Rational for Requirement R3** (page 6) which references the need to remain synchronized, an important aspect to specify: "The objective of Requirement R3 is to ensure that IBRs remain electrically connected, *synchronized*, and exchanging current, that is, continuing to operate during a frequency excursion event."

Likes 0	
Dislikes 0	

Response
The Standards Committee, with advisement from NERC, the 2020-02 Drafting Team, and leveraging the results of the September 4-5 Technical Conference on Ride-through have incorporated industry suggestions concerning the definition for "Ride-through". The resulting definition removes language that has been identified as either ambiguous or appears to specify performance requirements for how an IBR should recover following a grid disturbance. Similarly, "system" and "disturbance" are now lowercase terms. The definition now reads as: "The plant/facility remains connected and continues to operate through voltage or frequency system disturbances." A definition may be used by other standards. "As specified" would be unclear as to who or how these specifications are made. "Remaining synchronized" was previously rejected as it does not accurately define the operations of all IBR, as defined by Project 2020-06, during and immediately following all fault types.

Jennifer Neville - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Support MRO NSRF comments	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the response to MRO NSRF.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own. In addition, ERCOT notes that revising the definition of the term "Ride-through" to recognize that the continued operation associated with ride-through needs to be maintained not just through the Disturbance but all the way through recovery to a new operating point would result in a clearer definition that better aligns with PRC-030, which provides that IBR unit losses (partial trips) are not allowed. ERCOT supports the alternative definition of Ride-through that the SRC proposed, and ERCOT would also support revising that definition to read as follows: "Ride-through: The entire plant/facility **(including its dispersed power producing inverters)** remaining connected to the	

electric system and continuing in its entirety to operate in a manner that supports grid reliability through a System Disturbance, including the period of recovery back to a normal operating condition."	
Likes 0	
Dislikes 0	
Response	
The Standards Committee, with advisement from NERC, the 2020-02 Drafting Team, and leveraging the results of the September 4-5 Technical Conference on Ride-through have incorporated industry suggestions concerning the definition for "Ride-through". The resulting definition removes language that has been identified as either ambiguous or appears to specify performance requirements for how an IBR should recover following a grid disturbance. Similarly, "system" and "disturbance" are now lowercase terms. The definition now reads as: "The plant/facility remains connected and continues to operate through voltage or frequency system disturbances." Partial trips are specific performance parameters that are evaluated within PRC-030.	
Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The definition of ride-through should be updated as follows: "The entire plant/facility remaining connected to the Bulk Power System and contininuing in its entirety to operate ***as specified*** through System Disturbances ***inside defined limits***.	
Likes 0	
Dislikes 0	
Response	
The Standards Committee, with advisement from NERC, the 2020-02 Drafting Team, and leveraging the results of the September 4-5 Technical Conference on Ride-through have incorporated industry suggestions concerning the definition for "Ride-through". The resulting definition removes language that has been identified as either ambiguous or appears to specify performance requirements for how an IBR	

should recover following a grid disturbance. Similarly, "system" and "disturbance" are now lowercase terms. The definition now reads as: "The plant/facility remains connected and continues to operate through voltage or frequency system disturbances." "A definition may be used by other standards. "As specified" would be unclear as to who or how these specifications are made.	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no objections to the proposed definition of Ride-through definition.	
Likes 0	
Dislikes 0	
Response	

Thank you.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
NRG Energy Inc is in support of the comments made by EPSA.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes

Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI does not oppose the proposed definition of Ride-through.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Nick Leathers - Ameren - Ameren Services - 3 - SERC	
Answer	Yes
Document Name	
Comment	

Ameren does not have any additional comments for consideration by the drafting team.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company suggests using a different word or phrase for …"entire" plant/facility… to indicate that the expectation is that no equipment should drop out of service during the disturbance and remain connected throughout the disturbance. The use of the word "entire" could mean all plant equipment, including that which is already out of service for other reasons. Suggested wording: "The plant/facility shall remain connected and in service, maintaining the pre-distubance equipment configuration in operation, throughout the entirety of the system disturbance and recovery."	
Likes 0	
Dislikes 0	
Response	
The Standards Committee, with advisement from NERC, the 2020-02 Drafting Team, and leveraging the results of the September 4-5 Technical Conference on Ride-through have incorporated industry suggestions concerning the definition for "Ride-through". The resulting definition removes language that has been identified as either ambiguous or appears to specify performance requirements for how an IBR should recover following a grid disturbance. Similarly, "system" and "disturbance" are now lowercase terms. The definition now reads as: "The plant/facility remains connected and continues to operate through voltage or frequency system disturbances."	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
While WECC voted Affirmative, WECC suggests the DT emphasize the nature of the definition may not allow a single turbine or solar array to be lost in a System Disturbance (equates to failed "Ride-through" with loss).	
Likes 0	
Dislikes 0	
Response	
Thank you. Partial trips are specific performance parameters that are evaluated within PRC-030.	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
Thank you.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you.	
Greg Sorenson - Greg Sorenson On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you.	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	
Document Name	

Comment	
NRG agrees with and refers the SDT to the EPSA comments.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,Texas RE,NPCC,SERC,RF, Group Name SRC 2024	
Answer	
Document Name	
Comment	
In the proposed definition of "Ride-through", the ISO/RTO Council (IRC) Standards Review Committee (SRC) believes that the requirement that a facility continue "to operate" is inadequate; the definition needs to require the facility to maintain performance that is beneficial (or at the very least, not detrimental) to overall grid reliability. It is preferable if the ride-through definition referred to the electric system instead of the BPS to be consistent with the IBR definition. Finally, the concept of ride-through needs to recognize that the continued operation associated with ride-through needs to be maintained not just through the Disturbance but all the way through recovery to a new operating point. It is not clear that the existing Disturbance definition includes the recovery period. To address these concerns, the ride-through definition could be revised to read as follows:	

"Ride-through: The entire plant/facility remaining connected to the electric system and continuing in its entirety to operate in a manner that supports grid reliability through a System Disturbance, including the period of recovery back to a normal operating condition."	
Likes 0	
Dislikes 0	
Response	
Thank you. The definition cannot specify exact performance. From the Standard Processes Manual: **Definitions shall not contain statements of performance Requirements.** The Standards Committee, with advisement from NERC, the 2020-02 Drafting Team, and leveraging the results of the September 4-5 Technical Conference on Ride-through have incorporated industry suggestions concerning the definition for "Ride-through". The resulting definition removes language that has been identified as either ambiguous or appears to specify performance requirements for how an IBR should recover following a grid disturbance. Similarly, "system" and "disturbance" are now lowercase terms. The definition now reads as: "The plant/facility remains connected and continues to operate through voltage or frequency system disturbances."	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
NCPA is not registered to vote on this item and thus is not opposing it or FERC Order 901.	
Likes 0	
Dislikes 0	
Response	

Thank you.

2. Do you agree with the changes made in this draft of PRC-029-1?	
Jennifer Neville - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Support MRO NSRF comments	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the response to MRO NSRF.	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
We don't know if this proposal is going to improve reliability or the extent of reliability improvement, if any. The SDT has not shown us tangible relability improvement indices that support the modifications made. Considering this standard has been changed several times over the last few years we are skeptical that changes made will improve reliability. However, we do not oppose the proposal.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. PRC-029-1 is consistent with directives ordered by FERC and the SAR scope assigned to the drafting team.	
Srinivas Kappagantula - Arevon Energy - 5	
Answer	No
Document Name	
Comment	
Please see SEIA and NAGF comments on these standards. Lack of exemptions for frequency ride through requirements especially for older legacy IBR facilities is critically important as some of these plants may not be able to comply with this standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. This issue will be addressed in the upcoming draft.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC signed on to ACES comments: It is the opinion of ACES that the definition of what constitutes an IBR should be consistent across the industry. The Project 2020-02 SDT has been working diligently towards this goal and we do not believe that an individual standard should deviate from their approach. Thus we recommend removing the phrase “The Elements associated with” from section 4.2 and modifying this section as follows: 4.2. Facilities:	

4.2.1. Bulk Electric System (BES) IBRs; and

4.2.2. Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

R1. ACES believes that phrase "and is initiated by a non-fault switching event on the transmission system" should be struck from the 3rd bullet point of Requirement R1. It is our opinion that the GO will likely be unable to differentiate between an event initiated by a fault or an event initiated by a "non-fault switching event" on the Transmission system. In short, Transmission switching events are outside the purview of the GO.

R3/R4. ACES has grave concerns with the lack of any exceptions to Requirement R3 for existing IBRs. It is our opinion that Requirements R3 and R4 should be modified to include an exception for an IBR that is in-service by the effective date of PRC-029-1 and has a known hardware limitation that prevents the IBR from meeting Frequency Ride-through criteria.

R4. Lastly, it is ACES opinion that the acronym "CEA" should be spelled out in the first use within PRC-029-1 so as to eliminate any confusion as to what this term means. "CEA" is not a defined term and while it used in the NERC Rules of Procedure, it is not commonly used within the Reliability Standards.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
"The Elements" has been removed.
R1 bullet three is an optional exemption. GOs are not required to use any exemption from R1.
Frequency exemptions have been addressed in the latest draft.
CEA has been spelled out.

George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Edison Electric Institute's and Grid Strategies LLC's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response to EEI and Grid Strategies.	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	No
Document Name	
Comment	
PGAE recommends R3 and R4 to be revised to allow for existing IBR facility limitations for Frequenecy Ride Through, similar to the approach in R1 and R2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Frequency exemptions have been addressed in the latest draft.

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	

It is the opinion of ACES that the definition of what constitutes an IBR should be consistent across the industry. The Project 2020-06 SDT has been working diligently towards this goal and we do not believe that an individual standard should deviate from their approach. Thus we recommend removing the phrase “The Elements associated with” from section 4.2 and modifying this section as follows:

4.2. Facilities:

4.2.1. Bulk Electric System (BES) IBRs; and

4.2.2. Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

R1. ACES believes that phrase “and is initiated by a non-fault switching event on the transmission system” should be struck from the 3rd bullet point of Requirement R1. It is our opinion that the GO will likely be unable to differentiate between an event initiated by a fault or an event initiated by a “non-fault switching event” on the Transmission system. In short, Transmission switching events are outside the purview of the GO.

R3/R4. ACES has grave concerns with the lack of any exceptions to Requirement R3 for existing IBRs. It is our opinion that Requirements R3 and R4 should be modified to include an exception for an IBR that is in-service by the effective date of PRC-029-1 and has a known hardware limitation that prevents the IBR from meeting Frequency Ride-through criteria.

R4. Lastly, it is ACES opinion that the acronym "CEA" should be spelled out in the first use within PRC-029-1 so as to eliminate any confusion as to what this term means. "CEA" is not a defined term and while it used in the NERC Rules of Procedure, it is not commonly used within the Reliability Standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. "The Elements" has been removed. R1 bullet three is an optional exemption. GOs are not required to use any exemption from R1. Frequency exemptions have been addressed in the latest draft. CEA has been spelled out.	
Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	
Invenergy has the following comments regarding this draft of PRC-029-1: R1: Bullet 3 presents significant challenges, and it is unclear how an entity would demonstrate compliance with the design aspect of PRC-029-1. Generator Owners will likely not be able to properly model the non-fault switching event condition and would thus be unable to independently assure design adherence to that requirement. Remove "in whole or part" from Footnote 7 and Footnote 10. As drafted, the footnotes are inconsistent with IEEE-2800.	

Attachment 1 bullet 10 must be removed or significantly amended. Some protection decisions must be made in a matter of micro-seconds, and as drafted, bullet 10 would adversely impact reliability by subjecting equipment to potentially damaging surges of current or voltage that near instantaneous protection settings are designed to mitigate.

Invenergy disagrees with the SDT's interpretation of FERC Order 901, and we would like to reiterate that there is no clear evidentiary record to support the exclusion of limited exceptions from the frequency ride-through requirements. What's most concerning however is the SDT's recent assertion that it "does not have sufficient data at this time to determine whether additional frequency-based exemptions are appropriate and consistent with the overall reliability goals of Order No. 901." We continue to await the requested technical justification studies and would like to direct the SDT to the several public comments filed by OEMs in ERCOT's NOGRR 245 proceeding, that illustrate equipment challenges to meet reasonable data driven ride-through capability limits that fall below the current draft of PRC-029-1.

- **GE**

245NOGRR-58 GE Vernova Comments 110723.doc (live.com)

245NOGRR-63 GE Vernova Comments 011924.docx (live.com)

- **Vestas**

245NOGRR-57 Vestas Comments 110123.doc (live.com)

- **Siemens Gamesa**

245NOGRR-56 Siemens Gamesa Renewable Energy Comments 103023.docx (live.com)

Additionally, the SDT and NERC are encouraged to leverage the industry provided information regarding equipment limitations submitted according to provisions in the currently effectively Reliability Standard PRC-024-3.

As written, Draft 3 of PRC-029-1 ignores the technical realities surrounding many gigawatts of inverter-based resources installed on the BES today and **provides no path to compliance** for entities with well documented and understood hardware limitations. Invenergy would like to remind NERC that FERC has on many occasions, including within Order 901, granted NERC the leeway to exercise its technical expertise, experience, and discretion to develop appropriate requirements.

A reasonable path to compliance for facilities with equipment that is unable to meet the proposed voltage or frequency ride-through requirements would be to retain and carry over R3 from PRC-024-4. This would ensure equitable treatment of all generation types, provide sensible accommodations for equipment limitations, and push facilities to maximize their capabilities to the extent possible. In fact, FERC alluded to that in paragraph 193 of Order 901, stating, “We encourage NERC’s standard drafting team to consider currently effective Reliability Standard PRC-024-3, Requirement R3 as an example for establishing registered IBR technology exemptions.”

Absent limited exemptions from the ride-through requirements or a clear path to compliance for entities with hardware limitations, the frequency bands must be amended. To date, the SDT has provided no evidence that the proposed frequency bands, well beyond those of IEEE-2800-2002, would benefit BES reliability.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
R1 bullet three is an optional exemption. GOs are not required to use any exemption from R1.
The definition of “ride-through” has been modified.
Frequency exemptions have been addressed in the latest draft to address OEM design capability limits regarding frequency thresholds.
CEA has been spelled out.

Colin Chilcoat - Invenergy LLC - 6

Answer	No
Document Name	

Comment

Invenergy has the following comments regarding this draft of PRC-029-1:

R1: Bullet 3 presents significant challenges, and it is unclear how an entity would demonstrate compliance with the design aspect of PRC-029-1. Generator Owners will likely not be able to properly model the non-fault switching event condition and would thus be unable to independently assure design adherence to that requirement.

Remove “in whole or part” from Footnote 7 and Footnote 10. As drafted, the footnotes are inconsistent with IEEE-2800.

Attachment 1 bullet 10 must be removed or significantly amended. Some protection decisions must be made in a matter of micro-seconds, and as drafted, bullet 10 would adversely impact reliability by subjecting equipment to potentially damaging surges of current or voltage that near instantaneous protection settings are designed to mitigate.

Invenergy disagrees with the SDT’s interpretation of FERC Order 901, and we would like to reiterate that there is no clear evidentiary record to support the exclusion of limited exceptions from the frequency ride-through requirements. What’s most concerning however is the SDT’s recent assertion that it “does not have sufficient data at this time to determine whether additional frequency-based exemptions are appropriate and consistent with the overall reliability goals of Order No. 901.” We continue to await the requested technical justification studies and would like to direct the SDT to the several public comments filed by OEMs in ERCOT’s NOGRR 245 proceeding, that illustrate equipment challenges to meet reasonable data driven ride-through capability limits that fall below the current draft of PRC-029-1.

GE

245NOGRR-58 GE Vernova Comments 110723.doc (live.com)

245NOGRR-63 GE Vernova Comments 011924.docx (live.com)

Vestas

245NOGRR-57 Vestas Comments 110123.doc (live.com)

Siemens Gamesa

245NOGRR-56 Siemens Gamesa Renewable Energy Comments 103023.docx (live.com)

Additionally, the SDT and NERC are encouraged to leverage the industry provided information regarding equipment limitations submitted according to provisions in the currently effectively Reliability Standard PRC-024-3. As written, Draft 3 of PRC-029-1 ignores the technical realities surrounding many gigawatts of inverter-based resources installed on the BES today and **provides no path to compliance** for entities with well documented and understood hardware limitations. Invenergy would like to remind NERC that FERC has on many occasions, including within Order 901, granted NERC the leeway to exercise its technical expertise, experience, and discretion to develop appropriate requirements. A reasonable path to compliance for facilities with equipment that is unable to meet the proposed voltage or frequency ride-through requirements would be to retain and carry over R3 from PRC-024-4. This would ensure equitable treatment of all generation types, provide sensible accommodations for equipment limitations, and push facilities to maximize their capabilities to the extent possible. In fact, FERC alluded to that in paragraph 193 of Order 901, stating, "We encourage NERC's standard drafting team to consider currently effective Reliability Standard PRC-024-3, Requirement R3 as an example for establishing registered IBR technology exemptions." Absent limited exemptions from the ride-through requirements or a clear path to compliance for entities with hardware limitations, the frequency bands must be amended. To date, the SDT has provided no evidence that the proposed frequency bands, well beyond those of IEEE-2800-2002, would benefit BES reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. R1 bullet three is an optional exemption. GOs are not required to use any exemption from R1. The definition of "ride-through" has been modified. Frequency exemptions have been addressed in the latest draft to address OEM design capability limits regarding frequency thresholds. CEA has been spelled out.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	

Comment	
We concur with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you, please refer to response to EEI.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
NIPSCO recommends removing the phrase “demonstrate the design of each facility” from the proposed standard and returning to the original event-based requirements. The phrase may prove difficult to fully comply with, as a Functional Entity would have to know the design of the collector system and parameters and run the models correctly to demonstrate this. Much of this needed information would need to be provided by the manufacturer, which may require non-disclosure agreements. Please clarify or remove “other mechanisms” from requirement R2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	

Comments in previous drafts significantly desired to include design capability within PRC-029-1 to assist in determinations of compliance outside of experience. Entities will be required to have accurate models based on performance following the implementation of Milestone 3 directives of FERC Order No. 901. The usage of "other mechanisms" is to assure clarity that those are inclusive of requirements given outside of PRC-029-1; it is intended to prevent a GO from being non-compliant if required to operate differently than PRC-029-1.	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Requirement 2.1.1 through 2.1.3 are all required, recommend ensuring consistency in formatting and include an "and" at the end of 2.1.2. Request clarification of the intent of 2.1.3. The proposed language is not written clearly, and the intent is not apparent. Recommend at a minimum addressing this sub-requirement in the technical rationale. An additional recommendation is to provide clarification on how requirement 2.1.3 relates to the tables in Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. This item was not addressed during the technical conference.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	

R3. Wording "…and the absolute rate of change of frequency (RoCoF)12 magnitude is less than or equal to 5 Hz/second." should be removed from R3. The rate of change of frequency nas never been an issue in past IBR disturbances. In addition, PRC-024 does not mentions and includes rate of change of frequency requirements. There is no technical rationale for this.

R3. Requirement should include exceptions due to hardware limitation, the same exception that was given for voltage requirements. WEC Energy Group owns a wind farm with frequency limitation that may not meet PRC-029 requirements. Please explain what should we do? Do not overlook limited capabilities of older Type 3 wind IBRs. WEC Energy Group recognized similar concerns commented by industry, please address it.

WEC Energy Group suggests SDT to create and add graphs for support Tables 1 and 2 and the respective notes. Graphs should highlight "must Ride-through zone" and "may Ride-through zone" terms that are listed in note 11.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Frequency criteria and exemptions are addressed in the latest draft.

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	No
Document Name	

Comment

"Please see EEI Comments"

Likes 0	
Dislikes 0	

Response

Thank you, please see the response to EEI.

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	2020-02 LG&E KU Comments.docx
Comment	
Please see the attached comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Frequency exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds.	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not support the approval of PRC-029-1 because it intends to require existing resources to meet the frequency performance standards mandated in Requirement R3 and provides no mechanism for IBR resource owners to declare a technical exemption consistent with voltage ride-through requirements contained in Requirements R1 and R2. It is EEI's understanding that this was done because the drafting team (DT) understood that the FERC Order did not allow any exemption for frequency ride-through requirements. However, in Paragraph 193 of FERC Order No. 901, the Commission expressly directed NERC to determine through its standards development process whether the Reliability Standards mandated therein should include a limited exemption for certain IBRs from voltage ride-through performance requirements. Importantly, the Commission, in Order No. 901 did not concomitantly prohibit the inclusion of a similar exemption from frequency ride-through performance requirements, either expressly or implicitly. Rather, it left that decision firmly in the hands of subject matter experts, as was made evident when it encouraged "NERC's standard drafting team to consider currently effective	

Reliability Standard PRC-024-3, Requirement R3 **as an example for establishing registered IBR technology exemptions**." *Reliability Standards to Address Inverter-Based Resources*, Order No. 901, 185 FERC ¶ 61,042, at P 193 (2022) (emphasis added).

EEI further notes that we are unaware of any frequency ride-through events, beyond equipment control setting errors, that have been documented and cited in any of the NERC Event reports to justify a need to disallow reasonable equipment exemptions for IBRs that cannot meet the proposed frequency ride-through requirements. Nevertheless, PRC-029-1 contains requirements for frequency ride-through that are likely infeasible to implement through either hardware or software means, in many cases for existing resources. (Noting that while software upgrades might be a viable option for some newer IBRs, software solutions for older resources would not be a viable remedy because many of the older resources would not have the computing capability necessary to support such upgrades.)

To address our concerns, we recommend the following:

1. Change PRC-029-1 to include reasonable and justified exemptions for legacy IBR facilities. (*See edits to R4 below*)
2. Align the Frequency ride-through curve in PRC-029-1 with IEEE 2800-2022. (*Align Table 3 of attachment 2 to IEEE 2800-2022*)

PRC-029-1 (Requirement R4 – Changes in Boldface)

R4. Each Generator Owner identifying an IBR that is in-service by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting voltage **and frequency** Ride-through criteria as detailed in Requirements R1**,** R2, **and R3** and requires an exemption from specific Ride-through criteria shall*:10 Lower] [Time Horizon: Long-term Planning]*

4.1. Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1. This documentation shall include:

4.1.1 Identifying information of the IBR (name and facility #);

4.1.2 Which aspects of voltage **or frequency** Ride-through requirements that the IBR would be unable to meet and the capability of the hardware due to the limitation;

4.1.3 Identify the specific piece(s) of hardware causing the limitation;

4.1.4 Supporting technical documentation verifying the limitation is due to hardware that needs to be physically replaced or that the limitation cannot be removed by software updates or setting changes, and;

4.1.5 Information regarding any plans to remedy the hardware limitation (such as an estimated date). **4.2.** Provide a copy of the information detailed in Requirement R4.1 to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA no later than 12 months following the effective date of PRC-029-1. **4.2.1** Any response to additional information requested by the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA shall be provided back to the requestor within 90 days of the request. **4.2.2** Provide a copy of the acceptance of **a** hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s).11 **4.3.** Each Generator Owner with a previously accepted limitation that replace the hardware causing the limitation shall document and communicate such a hardware change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the hardware change. **4.3.1** When existing hardware causing the limitation is replaced, the exemption for that Ride-through criteria no longer applies.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Frequency exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds.	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	

See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response to EEI.	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation aligns with NAGF comments. Kimberly Turco on behalf of Constellation Energy Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the response to NAGF.	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	

Facilities:

4.2.1. The Elements associated with (1) Bulk Electric System (BES) IBRs inverter-based resources and (2) Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV

NextEra aligns with EEI's recommendation to remove "elements associated with" from Section 4.2.1

R1 and R2

NextEra believes that further clarity on reporting could be added to R1 and R2 consistent with the technical rationale.

R3

With a large portion of wind fleet across multiple OEMS, NextEra recommends there be an exception process for R3, or that it should not be applied retroactively. This is a particular concern for entrants for the Non-BES Assets.

R4

NextEra aligns with the below comments provided from EEI:

EEI does not agree with imposing new unverified requirements on existing resources as proposed in PRC-029-1 because it is unclear how many existing resources can meet the frequency performance standards mandated in Requirement 3. We are additionally concerned because resource owners have not been given adequate time to fully assess the impact of imposing these new requirements on their existing resources, which align with IEEE 2800-2022 (See 7.3.2.1 Figure 12 & Table 15 (Frequency ride-through, page 80; and see 7.3.2.3.5 Rate of change of frequency (ROCOF), page 82), and did not exist as a Standard until February 2022, after most of these resources were built or placed in service. For this reason, we cannot support the approval of PRC-029-1 without the following changes to Requirement 4 ensure that existing resources that were not design and do not have the capability to meet these requirements are allowed to declare an exemption for frequency ride-through similar to what is provided for resources that cannot meet the voltage ride-through requirements. See the proposed changes to R4 in boldface below:

R4. Each Generator Owner identifying an IBR that is in-service by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting voltage **and frequency** Ride-through criteria as detailed in Requirements R1**, and** R2, **and R3** and requires an exemption from specific **voltage** Ride-through criteria shall:*10 Lower] [Time Horizon: Long-term Planning]*

4.1. Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1. This documentation shall include:

4.1.1 Identifying information of the IBR (name and facility #);

4.1.2 Which aspects of voltage **or frequency** Ride-through requirements that the IBR would be unable to meet and the capability of the hardware due to the limitation;

{C}**4.1.3** Identify the specific piece(s) of hardware causing the limitation;

4.1.4 Supporting technical documentation verifying the limitation is due to hardware that needs to be physically replaced or that the limitation cannot be removed by software updates or setting changes, and;

4.1.5 Information regarding any plans to remedy the hardware limitation (such as an estimated date).

4.2. Provide a copy of the information detailed in Requirement R4.1 to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA no later than 12 months following the effective date of PRC-029-1.

4.2.1 Any response to additional information requested by the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA shall be provided back to the requestor within 90 days of the request.

4.2.2 Provide a copy of the acceptance of **an a** hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s).11

4.**3.** Each Generator Owner with a previously accepted limitation that replace the hardware causing the limitation shall document and communicate such a hardware change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the hardware change.

4.3.1 When existing hardware causing the limitation is replaced, the exemption for that Ride-through criteria no longer applies.

Footnote 7

"Available Real Power" is not NERC defined term located in the NERC Glossary of Terms. By adding to the footnote, this creates confusion.

NextEra recommends defining and adding to NERC Glossary.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Frequency exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds.

Megan Melham - Decatur Energy Center LLC - 5

Answer	No
Document Name	

Comment

Capital Power supports the NAGF's comments:

The NAGF strongly recommends that PRC-029 be revised to allow for frequency ride through ("FRT") exemptions to address such limitations for legacy IBR facilities. Not including FRT exemptions will result in a standard that will make certain IBR legacy facilities automatically non-compliant when the standards become effective.

Requirement R3 – the NAGF is concerned that legacy IBR facilities are not capable of meeting the 5 Hz/second maximum ROCOF or the 25-degree phase angle jump requirements. Therefore, FRT exemptions are necessary and need to be included in Requirement R3. In support of this concern, the NAGF points to the ERCOT NOGRR245 TAC Presentation, December 4, 2023 – page 4 which indicates that 40%

of OEMs cannot comply with the previously proposed specific 5 Hz/second maximum ROCOF requirement and 41% of OEMs cannot comply with the previously proposed specific 25-degree phase angle jump requirement. *December 4 2024 NOGRR245 TAC Stephen Solis - Principal System Operations Improvement* *Requirement R4.2.2 – the NAGF is unclear as to what the Compliance Enforcement Authority (CEA) acceptance for an IBR hardware limitation exemption will consist of. Will the CEA provide an email response confirming acceptance to the Generator Owner submitting the exemption? How are such exemptions to be submitted and to whom within the CEA organization?* In addition to the NAGF comments above, after discussions with a wind turbine OEM, some legacy equipment will not be able to handle the 64 Hz overfrequency ride-through requirement stipulated in PRC-029. Requiring IBRs to ride through an overfrequency in the range of 61.8 Hz to 64 Hz is beyond the IEEE 2800 standard, as stated by the SDT within the technical rationale. We recommend aligning the frequency ride-through requirement to be more in line with the IEEE 2800 standard and reducing the final "no-trip" overfrequency requirement to 61.8Hz in addition to changing the wording of Requirement R4 to allow for FRT exemptions. More discussions with IBR OEMs must be held to confirm equipment capabilities.	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the response to NAGF.	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation aligns with NAGF comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	

Dislikes 0	
Response	
Thank you, please see the response to NAGF.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The NAGF strongly recommends that PRC-029 be revised to allow for frequency ride through ("FRT") exemptions to address such limitations for legacy IBR facilities. Not including FRT exemptions will result in a standard that will make certain IBR legacy facilities automatically non-compliant when the standards become effective. *Requirement R3 – the NAGF is concerned that legacy IBR facilities are not capable of meeting the 5 Hz/second maximum ROCOF or the 25-degree phase angle jump requirements. Therefore, FRT exemptions are necessary and need to be included in Requirement R3. In support of this concern, the NAGF points to the ERCOT NOGRR245 TAC Presentation, December 4, 2023 – page 4 which indicates that 40% of OEMs cannot comply with the previously proposed specific 5 Hz/second maximum ROCOF requirement and 41% of OEMs cannot comply with the previously proposed specific 25-degree phase angle jump requirement.* *December 4 2024 NOGRR245 TAC Stephen Solis - Principal System Operations Improvement* *The NAGF recommends aligning exception language with IEEE-2800. The proposed PRC-029 ride through requirements do not include the technology limitations discussed in IEEE-2800.* *Requirement R4.2.2 – the NAGF is unclear as to what the Compliance Enforcement Authority (CEA) acceptance for an IBR hardware limitation exemption will consist of. Will the CEA provide an email response confirming acceptance to the Generator Owner submitting the exemption? How are such exemptions to be submitted and to whom within the CEA organization?*	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. Frequency exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
• AES CE believes additional changes are needed as explained below.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	No
Document Name	
Comment	
TransAlta supports multiple other organizations who recommend the addition of frequency ride-through to the allowable hardware limitations in R4.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Frequency exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds.	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 2	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the response to EEI.	
Michael Goggin - Grid Strategies LLC - 5	
Answer	No
Document Name	
Comment	

In the current draft of PRC-029, R4 should be modified to allow existing resources with equipment limitations to obtain an exemption from the frequency ride-through requirements in R3, instead of only allowing an exemption from the voltage ride-through requirements in R1 and R2. This is necessary because most existing IBR generators cannot meet the stringent frequency ride-through requirements proposed in R3 without deploying significant hardware modifications or replacement, which goes against the intent of FERC Order 901.

Without change, a large share of the 270 GW of operating IBR plants,[1] representing an investment of hundreds of billions of dollars, will be forced into early retirement. Abruptly forcing such a large volume of existing generators offline would not only impose massive costs, but also cause generation shortfalls in many regions. Such drastic action could be understandable if the frequency ride-through requirement were addressing a real reliability concern. However, NERC and the drafting team have repeatedly been unable to provide any technical justification for imposing the frequency ride-through requirement existing IBR plants. None of the reports NERC has published in response to IBR ride-through events have identified frequency ride-through as a significant concern. There is no reason to impose such a massive cost and reliability impact for a solution in search of a problem.

Information provided by the two largest IBR owners in the U.S. confirms that most existing IBRs cannot meet the frequency ride-through requirements. One of these developers indicated that more than 30% of its fleet could not comply with the draft standard. The other indicated that half of its operating IBR fleet has no viable path to compliance, and a large share of the remainder will require cost-prohibitive retrofits, so if the standard went into effect as drafted a large share of its operating fleet will have to be retired or fully repowered. Other developers that operate the remainder of the 270 GW IBR fleet would likely see comparable impacts. Retiring, or at best taking out of service for an extended period of time for repowering, such a large volume of facilities during a time of rapid growth in peak load and energy needs would cause far greater reliability concerns than whatever concern the frequency ride-through requirement is attempting to address.

Information provided by these developers indicates that a large share of wind, solar, and battery resources cannot meet the frequency ride-through standard without significant hardware replacement. The frequency ride-through requirements are particularly problematic for some existing wind generators. In the Technical Rationale document accompanying the second PRC-029 draft, the drafting team notes that some wind generators are more sensitive to frequency deviations, writing that “All IBR resources (except for type 3 wind turbines) interface to the grid through fast switching of power electronics devices. These power electronic devices are much less sensitive to the transmission system frequency excursion than non-hydraulic turbine synchronous resources.”[2] However, the drafting team then incorrectly concludes that “Therefore, IBR should be capable of riding through the increased proposed 6-second frequency ride-through requirement without risk of equipment damage or need for frequency protection to operate.” The Technical Rationale document does not offer any justification for its assumption that Type III wind turbines can meet the frequency ride-through requirements, despite noting that those turbines more directly interface with the grid and thus are more affected by frequency deviations than other IBRs.

In fact, many existing Type III wind turbines cannot meet the frequency ride-through requirements proposed in this draft of PRC-029. Those resources were designed to meet the reliability Standards and interconnection requirements that were in effect when they were placed in service, and were not designed to ride through frequency excursions of the magnitude and duration proposed in the draft Standard. Imposing a retroactive requirement on these generators is particularly problematic as it is not typically feasible to retrofit existing wind turbines to increase their ability to withstand mechanical stresses due to frequency changes. In such cases, making existing equipment better able to withstand frequency changes would require full replacement or extensive modification of hardware, which would come at a significant, and sometimes prohibitive, cost. At minimum, bringing wind plants that cannot meet the current standard into compliance would require replacing the turbine converter and controller. Further, frequency changes can impose mechanical stresses on highly sensitive elements in the wind turbine's rotating equipment, including the generator, gearbox, the main shaft, and bearings associated with all of that equipment, and requiring such resources to ride through frequency changes they were not designed to operate through can damage that equipment. Subjecting Type III wind turbines to this damage may lead to increased outages or premature failure of these generators, potentially increasing reliability risks. As noted above, if the standard went into effect as drafted a large share of the operating IBR fleet will have to be retired or fully repowered. Retiring these facilities during a time of rapid growth in peak load and energy needs would cause far greater reliability concerns than whatever concern the frequency ride-through requirement is attempting to address.

The Solution: Frequency ride-through exemptions for existing IBRs

The easiest solution is to modify R4 to allow existing resources with equipment limitations to obtain an exemption from the frequency ride-through requirements in R3, which would make PRC-029 consistent with a long precedent of FERC interconnection requirements and NERC Standards only applying prospectively, including PRC-024. Retroactive requirements impose a much greater financial burden on the generator than prospective Standards, and set a bad precedent by unfairly penalizing generators that met all requirements that were in effect at the time they were installed. Retrofit or replacement costs are typically much greater than if the capability were installed at the plant to begin with. In some cases parts needed for retrofits may not be available, particularly for models that have been discontinued or manufacturers that are no longer in business, potentially requiring the replacement of the entire power conversion system. Moreover, existing IBR generators typically sell their output at a fixed price under a long-term power purchase agreement, and unexpected retrofit or replacement costs cannot typically be recovered once a power purchase agreement has been signed. These unexpected and unrecoverable costs are far more concerning to lenders and other generation project financiers as they were not accounted for during the project's financing. As a result, retroactive requirements set a bad precedent by introducing regulatory uncertainty that makes future generation investment more uncertain and riskier, and likely more costly by forcing financiers to charge higher risk premiums. Changing the rules in the middle of the game and penalizing resources that were designed to the standards in effect at the time they were built also establishes a bad precedent, in addition to imposing costs that are not just and reasonable and undue discrimination relative to resources covered by PRC-024.

Fortunately, these problems can be fixed by simply inserting "R3" into the list of permissible exemptions in R4, which would allow existing resources with equipment limitations to obtain an exemption from the frequency ride-through requirements in R3.

In the Technical Rationale document, the drafting team points to FERC's directive in Order No. 901 to justify not allowing existing resources to obtain an exemption from the frequency ride-through requirements in R3: "FERC Order No. 901 states that this provision would be limited to exempting 'certain registered IBRs from voltage ride-through performance requirements.' This is the reason that no similar provisions are included for exemptions for frequency or rate-of-change-of-frequency (ROCOF) ride-through requirements per R3."[3]

However, a contextual reading of Order No. 901 indicates FERC was focused on targeting equipment limitation exemptions at existing generators that would have to physically replace or modify hardware to comply with the Standard, and not focused on limiting such exemptions to voltage ride-through requirements. Paragraph 193 in its entirety, and particularly the first sentence, explain that FERC's intent was exempting existing resources that would have to physically replace or modify hardware: "we agree that a subset of existing registered IBRs –typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements directed herein." As a result, FERC continued by directing that "Any such exemption should be only for voltage ride-through performance for those existing IBRs that are **unable to modify their coordinated protection and control settings to meet the requirements without physical modification of the IBRs' equipment**."[4]

Allowing existing plants to apply for an equipment limitation exemption for the frequency ride-through requirements in R3 is necessary to ensure some existing generators do not have to physically replace or modify hardware, as explained above. As a result, such an exemption is consistent with FERC's directive and intent in Order No. 901. As documented in the following footnote, there is ample precedent for NERC and standards drafting teams to exercise their technical expertise to craft Standards to align content and requirements with technical realities.[5]

Additional context in Order 901 further demonstrates that FERC intended for NERC to include an exemption for existing IBRs that cannot meet frequency ride-through requirements. At paragraph 190 in Order No. 901, FERC directed NERC to develop Standards that ensure resources "ride through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults." For many existing IBRs that cannot meet the proposed frequency ride-through requirements, tripping is necessary to protect the IBR equipment, similar to when synchronous generation resources use tripping as protection from internal faults. As a result, an exemption from R3 for existing resources is consistent with FERC's intent. Order No. 901 also directed NERC to consider the "PRC-024-3, Requirement R3 as an example for establishing registered IBR technology exemptions," and that exemption applies equally to voltage ride-through and frequency ride-through settings, further suggesting that FERC will allow certain IBRs an exemption from the frequency ride-through requirements.[6] Finally, Order No. 901 notes that in the notice of proposed rulemaking that led to the order, FERC "proposed to direct NERC to develop new or modified Reliability Standards that would require registered IBR facilities to ride through system frequency and voltage disturbances where technologically feasible."[7] FERC then adopted that very proposal,{C}[8] further demonstrating that FERC sought to direct NERC to only require frequency and voltage ride-through where technologically feasible.

When asked about this issue, FERC staff has indicated that as a general matter, when a Commission Order is silent on a topic it is neither requiring something nor requiring the absence of that thing. NERC is taking a contrary position by arguing that due to FERC's silence they are not allowed to give an exemption for frequency ride-through.

NERC has been unable to present any technical reason why FERC would not allow a frequency ride-through exemption for existing IBRs, as none exists. Frequency ride-through has not been identified as a significant concern in any of the reports NERC has commissioned regarding IBR ride-through during disturbance events. Moreover, there is no technical justification for requiring existing IBRs to meet the extremely wide frequency ride-through bands proposed in PRC-029. PRC-029 requires IBRs to remain online for 6 seconds at 56-64 Hz, 5 minutes at 57-61.8, 11 minutes at 58.5-61.5, and indefinitely at 58.8-61.2 Hz. Under-Frequency Load Shedding (UFLS) that restores frequency following an extreme disturbance typically begins at 59.4 or 59.5 Hz. There is no credible reliability reason for requiring IBRs to remain online for 5 minutes for excursions that are 5 times more severe than the threshold at which UFLS restores frequency, and indefinitely for a frequency excursion twice as severe as that threshold. Such a requirement for IBRs is particularly pointless because PRC-024 would have allowed synchronous resources' relays to trip those generators far before that point for far less severe excursions.

This highlights another likely reason FERC Order No. 901 did not explicitly direct NERC to include frequency ride-through exemptions: FERC did not anticipate that NERC would adopt such a strict frequency ride-through requirement that some existing IBR plants cannot meet it. The drafting team even notes at page 7 in the Technical Rationale document that "The proposed 6-second time frame of the frequency ride-through capability requirement is beyond the IEEE 2800 standard frequency ride-through requirement and beyond frequency ride-through requirements for synchronous machines under proposed PRC-024-4." There is nothing in Order No. 901 that suggests that FERC was opposed to existing equipment exemptions for a frequency ride-through standard that was drafted after FERC issued Order No. 901 and is more stringent than FERC anticipated. A much more reasonable interpretation is that the logic FERC provided in paragraph 193 of Order No. 901 also applies to a frequency ride-through requirement that some existing resources cannot meet without physical modification or replacement of equipment. In fact, paragraph 193 makes clear that FERC's language focuses on an exemption from voltage ride-through requirements because "a subset of existing registered IBRs… may be unable to implement the voltage ride though performance requirements directed herein."

At the end of paragraph 193, FERC also explained that an exemption for existing resources would not harm reliability because "The concern that there are existing registered IBRs unable to meet voltage ride through requirements should diminish over time as legacy IBRs are replaced with or upgraded to newer IBR technology that does not require such accommodation." FERC's reasoning in paragraph 193 also applies to an exemption from frequency ride-through requirements, but particularly the conclusion that exempting existing plants does not cause reliability concerns and therefore should be allowed. The NERC drafting team's technical justification document explicitly explains that the frequency ride-through requirement is "to ensure the reliability of future grids with high IBR penetration," {C}[9] based on concerns about declining inertia due to IBRs replacing synchronous resources. NERC and others have demonstrated that inertia and frequency response will remain more than adequate for the foreseeable future even following disturbances that are several times larger than current credible contingencies, and that higher IBR penetrations can actually significantly improve frequency stabilization following disturbances.[10]

As a result, there is no reliability concern from an exemption for the small number of existing resources that cannot meet the requirements without physical modification or replacement of equipment. Moreover, as FERC notes, these plants will replace that equipment anyway over time as legacy inverters fail or are replaced with more modern equipment for other reasons, and the draft standard requires replacement equipment to comply with the Standard. Utility-scale inverters installed at solar and battery installations typically come with warranties of 10 years or less,{C}[11] and those inverters are typically replaced at least once during the plant's lifetime. Many existing wind plants are also being repowered with newer turbines, often to allow the project to receive another 10 years of production tax credits after the initial 10 years of credits have been received. As a result, by the time the drafting team's concerns about inertia in a high IBR penetration future might materialize, the vast majority of IBRs that cannot meet the frequency ride-through requirements will have been replaced with new equipment that is not exempt.

Moreover, the drafting team's assumption that frequency deviations will be larger on a future low inertia power system is flawed. IBRs can provide fast frequency response, which stabilizes frequency in the initial seconds following a grid disturbance, before synchronous generators begin to provide their slower primary frequency response.[12] Thus fast frequency response provides a similar service to inertia in helping to arrest the change in frequency before primary frequency response is fully deployed, reducing the need for inertia. [13] Fast frequency response is easily provided by batteries due to their available energy, but can also be provided by curtailed wind or solar resources. Power systems with high IBR penetrations will tend to have some wind or solar curtailment in a significant share of hours. If allowed to do so, solar an battery resources with spare DC capacity behind the inverter can also temporarily exceed their interconnection agreement's AC injection limit to provide fast frequency response.

The replacement of inflexible synchronous resources with more flexible IBRs could also significantly improve primary frequency response, as NERC's modeling has demonstrated.{C}[14] NERC has also documented that only about 30% of synchronous generators provide primary frequency response, and only about 10% provide sustained primary frequency response.[15] Even with less inertia, the fast and accurate frequency response provided by IBRs will keep frequency more tightly controlled than the slow to nonexistent primary frequency response from synchronous generators. The replacement of large synchronous generators with smaller IBRs should also reduce the magnitude of frequency deviations following the loss of generators. If frequency response does begin to emerge as a concern, the more effective solution would be to enforce requirements on synchronous generators that are supposed to provide it but do not. If necessary, operators would alter real-time dispatch, as ERCOT and some island power systems occasionally do today, to ensure that inertia and fast frequency response are adequate to ensure under-frequency load shedding or generator tripping thresholds are not reached. Finally, grid-forming inverters are increasingly being deployed with battery storage and other IBR installations, further increasing the contributions of IBRs to stabilizing frequency.

At page 8 in the Technical Rationale document, the drafting team argues that "To compensate for the lack of inertia and short circuit contributions, [IBRs] should have wider tolerances for frequency and voltage excursions to meet the needs of future power systems with a higher percentage of IBR." The drafting team also argues that IBRs should have to ride-through much larger frequency deviations than synchronous resources because "Synchronous resources are more sensitive to frequency deviations than IBR resources." This logic is flawed for many reasons. Grid operators need all resources to ride through disturbances, and the contribution of a resource to inertia or short circuit needs is irrelevant to that need. Any concerns about resources' inertia and short circuit contributions are outside the drafting team's scope and authority, and should be addressed by other means (such as by increasing the deployment of grid-forming IBRs in the localized areas that have short circuit or stability concerns). It is also perverse for the drafting team to penalize IBRs for being less sensitive to frequency deviations than synchronous generators. As noted below, there are already grounds for FERC to reject this proposed standard due to undue discrimination against IBRs relative to the far more lenient requirements on synchronous generators under PRC-024, including an equipment limitation exemption for synchronous generators from the frequency relay setting requirement in PRC-024,[16] and this only adds to those concerns.

In short, the drafting team's unfounded concerns about a future power system do not justify withholding an exemption to frequency ride-through requirements for existing IBRs that will have been largely replaced by the time any concerns might materialize.

Finally, R4 equipment limitation exemptions should be allowed for resources with signed interconnection agreements as of the effective date of the Standard, instead of resources that are in-service as of that date. Resource equipment decisions are typically locked down at the time the interconnection agreement is signed, and a change in requirements after that point can require a costly change in equipment or settings that may also trigger a material modification and resulting interconnection restudies. The implementation plan for PRC-029 indicates that the effective date for the Standard will be the first day of the first quarter six months after FERC approval. Many resources take significantly longer than that to move from a signed interconnection agreement to being placed in service, so it makes more sense to allow R4 equipment limitation exemptions for resources that have a signed interconnection agreement as of the effective date of the Standard.

The current draft of the PRC-029 Standard is unworkable and will impose massive costs on some existing generators with no benefit for reliability. As explained above, the drafting team incorrectly ventures that "IBR should be capable of riding through the increased proposed 6-second frequency ride-through requirement without risk of equipment damage or need for frequency protection to operate," even after noting that some wind turbines use very different technology. NERC's rigorous standard development process exists to ensure that errors like this do not make it into final Standards, and the exceedingly low level of support for the initial draft and the major revisions in the current draft indicate that further revisions will likely be necessary. It takes time to fine tune highly technical requirements and vet them across the industry to avoid unnecessary and exorbitant costs for existing resources that cannot meet the standard.

If PRC-29 continues to fall short of the level of support required for approval in this round of balloting, and NERC proceeds under Rules of Procedure Rule 321.2.1 by having the Standards Committee convene a technical conference and use the input from the technical conference to revise the standard for a final re-balloting period, incorporating an exemption from the frequency ride-through requirement for existing IBR generators would help to secure sufficient support for the standard to pass during re-balloting. Irreparable and immediate harm will occur if PRC-029 is allowed to move forward in its current form, harm that cannot be undone even if NERC immediately opens a standards revisions effort after the adoption of PRC-029 to fix these concerns. The current implementation plan requires BES IBRs to "ensure the design of their IBR units meets the criteria" within 12 months following regulatory approval of the standard, while for non-BES IBRs the compliance deadline will be the later of January 1, 2027, or 12 months following regulatory approval of the standard.[17] A year or two provides IBR owners with no time to wait if hundreds of GW of existing IBRs are required to secure retrofit or replacement equipment, find skilled technicians and tools to install that equipment, and complete that work during scheduled plant outages, especially since the entire industry will be pulling from the same pool of equipment and skilled labor. As a result, if

PRC-029 is approved in its current form, IBR owners will immediately begin incurring massive non-refundable costs for equipment orders and labor contracts, as they cannot wait in the hope that a subsequent revision effort will fix this error. Moreover, the typical timeline from Standard Authorization Request through standard balloting and FERC approval is much more than a year, so industry would have no reason to expect such an effort could be completed before PRC-029 took effect.

Alternative solutions

If NERC refuses to accept that Order 901 allows it to exempt existing IBRs from the frequency ride-through requirement, alternative solutions can mitigate the harm the proposed standard would cause. One alternative solution would be modifying the standard to allow IBRs, or at least existing IBRs, to meet far less stringent frequency ride-through curves than those proposed in PRC-029. The less stringent frequency ride-through curve or curves could be taken from PRC-024. As noted above, the PRC-024 curves are closer to but still significantly wider than UFLS thresholds, and thus are better tailored to meeting actual reliability needs. An additional advantage is that the PRC-024 curves have been in place for many years and thus many existing IBRs were designed with relays that would not trip them for disturbances of that magnitude. In contrast, the curves proposed in PRC-029 are far more stringent than past design practice and could not have been anticipated by IBRs when they were built. Industry could work to identify a reasonable and attainable frequency ride-through curve or curves at the technical conference that will likely be convened due to Rule 321.2.1, which could then be incorporated into the revised standard that subsequently goes out for a final re-balloting period.

This approach will not mitigate all of the harm caused by PRC-029, as PRC-024 still allows exemptions for equipment limitations,[18] while NERC is taking the position that PRC-029 cannot. Moreover, adopting something approximating the PRC-024 curves in PRC-029 would still result in disparate treatment for IBRs because PRC-024 is only a relay-setting standard and PRC-029 is a ride-through performance requirement. The most elegant solution, and the one least likely to result in a costly mistake that requires expensive retrofits and plant retirement for no reliability benefit, and risk FERC rejection of the standard, is to simply include an exemption for existing resources.

Undue discrimination

Providing an exemption in PRC-029 R4 for existing IBRs that cannot meet the frequency ride-through requirement in R3 will provide less disparity with the treatment of synchronous resources under PRC-024, and is therefore an essential step if NERC wants to reduce the risk of FERC rejecting the proposed standard due to undue discrimination against IBRs. As noted above, PRC-024 allows exemptions for equipment limitations,[19] so exempting existing IBRs from PRC-029's frequency ride-through requirements would reduce the undue discrimination towards IBRs.

It should also be noted that PRC-029 is far more stringent because it is a ride-through performance requirement, while the existing and proposed versions of PRC-024 are simply relay-setting standards. PRC-024 only requires protective relays to be set so they do not trip the generator within specified bounds, but it allows a resource to trip offline for other reasons. PRC-024-4 explicitly allows a plant to trip if protection systems trip auxiliary plant equipment, per section 4.2.3. In contrast, PRC-029 is a performance standard that requires IBRs to remain electrically connected and to continue to exchange current within the specified voltage and frequency bounds. Said another way, an IBR and a synchronous resource could both trip during the same disturbance, and the IBR would be in violation of PRC-029 but the synchronous generator would not be in violation of PRC-024-4, as long as the synchronous generator did not trip due to the settings of its protection system.

To ensure grid reliability and resilience, all resources including IBRs and synchronous resources should ride through grid disturbances. The failure of synchronous generators to ride through grid disturbances threatens grid reliability as much or more than the failure of IBRs, as synchronous resources are often producing at a higher level of output, are more typically relied on as capacity resources, and often take longer to come back online and ramp up to full output if they trip due to a disturbance.

FERC Order No. 901 directed NERC to treat IBRs similarly to how NERC Standards treat synchronous generators, writing that the IBR Standard should "permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults."{C}[20] Allowing synchronous generators to trip but requiring IBRs to ride through the same or similar disturbance could be challenged at FERC as undue discrimination. Providing synchronous generators with an exemption from PRC-024's frequency relay setting requirements but not offering IBRs an exemption from the far more stringent frequency ride-through requirements in PRC-029 only compounds the undue discrimination, and makes an even stronger case for FERC to reject PRC-029 as proposed.

Not requiring ride-through performance from synchronous generators is also at odds with the intent for this project that NERC stated in its February 2023 comments on the FERC proposed rulemaking that led to Order No. 901: "A comprehensive, performance-based ride-through standard is needed to assure future grid reliability. To that end, NERC re-scoped an existing project, Project 2020-02 Modifications to PRC-024 (Generator Ride-through), to revise or replace current Reliability Standard PRC-024- 3 with a standard that will require ride-through performance from all generating resources."[21] FERC's Order No. 901 also noted NERC's statement that this project would require ride-through performance from all generating resources,[22] so a failure to require ride-through performance from synchronous generators is contrary to both NERC's and FERC's intent.

Providing an exemption in PRC-029 R4 for existing IBRs that cannot meet the frequency ride-through requirement in R3 will provide less disparity with the treatment of synchronous resources under PRC-024, and is therefore an essential step if NERC wants to reduce the risk of FERC rejecting the proposed standard due to undue discrimination against IBRs.

{C}[1]{C} https://www.utilitydive.com/news/clean-energy-capacity-wind-solar-2024-acp-report/715501/

{C}[2]{C} Technical Rationale, PRC-029-1 – Frequency and Voltage Ride-Through Requirements for Inverter-Based Generating Resources, at 8, https://www.nerc.com/pa/Stand/202002_Transmissionconnected_Resources_DL/2020-02_PRC-029-1_Technical_Rationale_Redline_to_Last_Posted_06182024.pdf ("Technical Rationale").

{C}[3]{C} *Id.*, at 10

{C}[4]{C} *Reliability Standards to Address Inverter-Based Resources*, Order No. 901, 185 FERC ¶ 61,042, P 193 (2023).

{C}[5]{C} For example, **Section 215(d)(2) of the FPA** requires FERC to give "due weight" to the technical expertise of the ERO when evaluating the content of a proposed Reliability Standard or modification to a Standard.

Order No. 733-A, P 11: "In this order, we emphasize and affirm that we do not intend to prohibit NERC from exercising its technical expertise to develop a solution to an identified reliability concern that is equally effective and efficient as the one proposed in Order No. 733."

Order No. 748, P 43: "In consideration of these ongoing efforts, we will not direct specific modifications to these Reliability Standards and, rather, accept NERC's commitment to exercise its technical expertise to study these issues and develop appropriate revisions to applicable Standards as may be necessary."

Order No. 896, P 36: "NERC may also consider other approaches that achieve the objectives outlined in this final rule. Further, as recommended by PJM, we believe there is value in engaging with national labs, RTOs, NOAA, and other agencies and organizations in developing benchmark events. Considering NERC's key role, technical expertise, and experience assessing the reliability impacts of various events and conditions, we encourage NERC to engage with national labs, RTOs, NOAA, and other agencies and organizations as needed."

Order No. 901, P 192: "We believe that, through its standard development process, NERC is best positioned, with input from stakeholders to determine specific IBRs performance requirements during ride through conditions, such as type (e.g., real current and/or reactive current) and magnitude of current. NERC should use its discretion to determine the appropriate technical requirements needed to ensure frequency and voltage ride through by registered IBRs during its standards development process."

{C}[6]{C} Order 901, P 193

{C}[7]{C} *Id.* at P 178.

{C}[8]{C} *Id.* at P 190.

{C}[9]{C} Technical Rationale at 7.

{C}[10]{C} East Interconnection Frequency Response Assessment with Inverter Based Resources, at 7 https://www.energy.gov/sites/prod/files/2018/07/f53/2.1.4%20Frequency%20Response%20Panel%20-%20Velummylum%2C%20NERC.pdf.

{C}[11]{C} Best Practices for Operation and Maintenance of Photovoltaic and Energy Storage Systems, at 55, https://www.nrel.gov/docs/fy19osti/73822.pdf.

{C}[12]{C}Fast Frequency Response Concepts and Bulk Power System Reliability Needs, https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf.

{C}[13]{C} Inertia and the Power Grid: A Guide Without the Spin, https://www.nrel.gov/docs/fy20osti/73856.pdf.

{C}[14]{C} East Interconnection Frequency Response Assessment with Inverter Based Resources, at 7 https://www.energy.gov/sites/prod/files/2018/07/f53/2.1.4%20Frequency%20Response%20Panel%20-%20Velummylum%2C%20NERC.pdf.

{C}[15]{C} https://www.nerc.com/pa/Stand/Project%20200712%20Frequency%20Response%20DL/FRI_Report_10-30-12_Master_w-appendices.pdf

{C}[16]{C} https://www.nerc.com/pa/Stand/202002_Transmissionconnected_Resources_DL/2020-02_PRC-024-4_Draft_2_Clean_06182024.pdf, R3, at pages 5-6

{C}[17]{C} https://www.nerc.com/pa/Stand/202002_Transmissionconnected_Resources_DL/2020-02_PRC-024-4_PRC-029-1_Implementation%20Plan_Redline_to_Last_Posted_07222024.pdf

{C}[18]{C} https://www.nerc.com/pa/Stand/202002_Transmissionconnected_Resources_DL/2020-02_PRC-024-4_Draft_2_Clean_06182024.pdf, R3, at pages 5-6

{C}[19]{C} https://www.nerc.com/pa/Stand/202002_Transmissionconnected_Resources_DL/2020-02_PRC-024-4_Draft_2_Clean_06182024.pdf, R3, at pages 5-6

{C}[20]{C} Order No. 901, at P190

[21]{C}https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Comments_IBR%20Standards%20NOPR.pdf, at 21-22.

[22]{C} Order No. 901, at P185

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Frequency exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds.

Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

1. Requirements R1, R2 and R3 use the phrase “ensure design and operation” to imply a Generator Owner is required to guarantee an IBR will be operated in Real-time as designed. We observe the Standard Drafting Team’s (SDT) previous response to the meaning of this phrase is clarified through the “additional specificity and examples for objectively evaluating compliance” within each requirement’s measure. We believe this is outside the scope of the NERC Protection and Control Reliability Standards, as only a Generator Operator can make such guarantees. The scope of the Protection and Control Reliability Standards are to ensure

facility equipment is properly configured and with settings that achieved sufficient and observable reliability during facility operating simulations. Several of these Reliability Standards have periodicities that ensure the initial design philosophy is still being achieved through repeatable simulations, even years after a facility's commissioning date. The purpose of NERC Reliability Standard PRC-005-6 is to ensure a facility's Protection Systems, particularly relays, are maintained within their intended design settings. We believe the phrase proposed by the SDT should be clarified to imply designed to operate under simulated conditions and disturbances. For Requirement R1, we propose this clarification for consideration, "Each Generator Owner shall ensure each IBR is designed, both initially and following the IBR's commissioning, to meet or exceed the Ride-through requirements in accordance with the Continuous Operation Region specified in Attachment 1."

2. We believe the possibility of an IBR limitation should not be limited to hardware. In the past, such limitations may have been imposed on Generator Owners because some equipment manufacturers were unable to achieve functional requirements through firmware modifications. Moreover, some equipment manufacturers terminated their business operations entirely. We believe the SDT should broaden each reference within the Reliability Standard and omit any descriptive adjectives associated with a limitation.
3. Part 2.1.3 states during a voltage excursion, each Generator Owner shall ensure the design of its IBR is set to prioritize Real Power or Reactive Power, unless overridden by another registered entity, when the voltage at the high side of the main power transformer is less than 0.95 per unit, yet still within the continuous operation region as specified in Attachment 1, and the IBR cannot deliver both Real Power and Reactive Power. We believe the SDT could simplify this language, as the Generator Owner will not have enough information of the Bulk Power System to make an informed decision on the appropriate priority during anticipated system conditions and configurations in the future. We believe the SDT should instead clarify the default priority for Generator Owners is Reactive Power, like Part 2.2.
4. Under Requirement R3, each Generator Owner is required to ensure its IBRs meet or exceed the Ride-through requirements during a frequency excursion event whereby the absolute rate of change of frequency (RoCoF) magnitude is less than or equal to 5 Hz/second. This requirement assumes the configurable function is enabled. We recommend the SDT clarify the absolute rate of change of frequency (RoCoF) magnitude requirement is set only when such a function is enabled.
5. To summarize Requirement R4, any limitations identifying an IBR is unable to meet the voltage Ride-through criteria detailed in Requirements R1 and R2 must be documented. Under the individual parts of this requirement, there is no option available for a Generator Owner to have a limitation indefinitely applied. We also believe Parts 4.1.4 and 4.1.5 require supporting technical documentation and plans to correct a limitation as possible language that should be incorporated in the requirement's measure.
6. We believe the SDT should modify the language of each measure for Requirements R1, R2, and R3. The phrase "but are not limited to" should be removed within each measure. The possible evidence identified should not imply that each example is needed. We also recommend replacing the "and" within the items of a series with an "or."

7. As defined within Section 2.5 of Appendix 3A (Standard Processes Manual) of the NERC Rules of Procedure, a Measure “provides identification of the evidence or types of evidence that may demonstrate compliance with the associated requirement.” We believe the reference to “shall” within each measure of a requirement of this proposed Reliability Standard is misaligned with the NERC Rules of Procedure. For instance, as proposed, each Generator Owner is required to retain evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate the operation of each IBR did adhere to Ride-through requirements. Such data may not be available because of equipment failures that are then handled through compliance with other Reliability Standards. Entities also need to implement their own internal processes to extract this data before a limited storage capacity overrides this historical information. We believe the Standard Drafting Team should instead focus on identifying evidence that may demonstrate compliance, such as an ongoing design philosophy that each IBR will meet the Ride-through requirements in accordance with the Continuous Operation Regions specified within the Reliability Standard’s attachments.
8. We believe a significant burden has been placed on Generator Owners with the expectation listed within Measure M2 that the Generator Owner will retain, for each voltage excursion, actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate that the operation of each IBR did adhere to this Reliability Standard’s performance requirements. It should be noted that other proposed Reliability Standards are placing limitations on which voltage excursions are applicable for analysis. A similar burden is listed within Measure M3 with each frequency excursion. We recommend the SDT remove this burden entirely. Instead, we propose offering a Generator Owner an opportunity to provide their IBR’s equipment settings for the period prior to the facility’s commissioning and actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data at the Generator Owner’s discretion. If the Generator Owner needs to demonstrate their facility’s performance following a Disturbance, the actual disturbance monitoring data will be requested under Reliability Standard PRC-030-1. Moreover, such a request should originate from an external reliability entity and not require the Generator Owner to collect actual disturbance monitoring data following each voltage or frequency excursion.
9. We believe the mathematical symbol associated the 1.10 per unit voltage range listed in Attachment 1, Table 2, should be greater than and equal to” instead of just “greater than.”

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
1, 2, 4, 5, 8. The approach by the drafting team is consistent with FERC Order No. 901 and the assigned SAR to this drafting team.

3. Performance is to prioritize based on pre-established requirements with TOs. IBR are not required to prioritize both.
6. Measures are to assist in compliance and are not enforceable.
7. See PRC-028 for data requirements. Multiple SER and DR data points are required to be captured per that standard.
9. No change has been made to this chart.

Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
See EEi comments	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see the response to EEI.	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
NRG Energy Inc is in support of the comments made by EPSA.	
Likes 0	
Dislikes 0	
Response	

Thank you. Please see the response to EPSA.

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	

(A) Duke Energy agrees with and supports EEI R4 comments for the three reasons cited by EEI because it is unclear how many existing resources can meet the frequency performance standards mandated in Requirement 3 and resource owners have not been given adequate time to fully assess the impact of imposing these new requirements on their existing resources,

(B) Duke Energy disagrees with the language in Measures 1-3 and recommends alternative language as stated below:

Measures 1-3 generally states:

"Each Generator Owner shall retain evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate the operation of each facility IBR did adhere to Ride-through requirements," as specified in Requirement 1/2/3.

This statement requires heavy administrative burden and data storage since it would require capturing data daily and downloading the data to a storage location separate from the DDR,FR, & SER; since this equipment has low memory thresholds, memory could be exceeded. Accordingly, the TO/TOP would be required to notify the GO of a grid frequency event and data could be overwritten prior to TO/TOP notification.

Recommendation:

Each Generator Owner shall retain evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data, "upon notification for TO/TOP" to demonstrate the operation of each facility IBR did adhere to Ride-through requirements "or notification of data overwrite to TO/TOP."

(C) Measure 1, 2 and 3 language is not consistent (suggested corrections added below):

- The word data was eliminated from M1: …Fault Recorder) “data” to demonstrate… - The word ride-through was eliminated from M2: …IBR will adhere to “Ride-through” requirements, as specified in Requirement… - Did the SDT intentionally substitute “performance” for “Ride-through requirements” in M2 – see second sentence excerpt below? …each IBR did adhere to “Ride-through requirements”, as specified in Requirement…	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see the responses to PRC-028-1 regarding data requirements and preservation of disturbance monitoring data as well as PRC-030-1 for analytical triggers. A GO is not required to independently determine when a system disturbance has occurred.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
TEPC agrees with EEI's comments regarding PRC-029-1, requirement 4. EEI does not agree with imposing new unverified requirements on existing resources as proposed in PRC-029-1 because it is unclear how many existing resources can meet the frequency performance standards mandated in Requirement 3. We are additionally concerned because resource owners have not been given adequate time to fully assess the impact of imposing these new requirements on their existing resources, which align with IEEE 2800-2022 (See 7.3.2.1 Figure 12 & Table 15 (Frequency ride-through, page 80; and see 7.3.2.3.5 Rate of change of frequency (ROCOF), page 82), and did not exist as a Standard until February 2022, after most of these resources were built or placed in service. For this reason, we cannot support the approval of PRC-029-1 without the following changes to Requirement 4 ensure that existing resources that were not design and do not have the capability to meet these requirements are allowed to declare an exemption for frequency ride-through similar to what is provided for resources that cannot meet the voltage ride-through requirements.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. Frequency exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	

AZPS Supports the following comments that were submitted by EEI on behalf of its members:

EEI does not agree with imposing new unverified requirements on existing resources as proposed in PRC-029-1 because it is unclear how many existing resources can meet the frequency performance standards mandated in Requirement 3. We are additionally concerned because resource owners have not been given adequate time to fully assess the impact of imposing these new requirements on their existing resources, which align with IEEE 2800-2022 (See 7.3.2.1 Figure 12 & Table 15 (Frequency ride-through, page 80; and see 7.3.2.3.5 Rate of change of frequency (ROCOF), page 82), and did not exist as a Standard until February 2022, after most of these resources were built or placed in service. For this reason, we cannot support the approval of PRC-029-1 without the following changes to Requirement 4 ensure that existing resources that were not design and do not have the capability to meet these requirements are allowed to declare an exemption for frequency ride-through similar to what is provided for resources that cannot meet the voltage ride-through requirements. See the proposed changes to R4 below:

R4. Each Generator Owner identifying an IBR that is in-service by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting voltage and frequency Ride-through criteria as detailed in Requirements R1**,** R2, and R3 and requires an exemption from specific Ride-through criteria shall*:*

4.1. Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1. This documentation shall include:

4.1.1 Identifying information of the IBR (name and facility #);

4.1.2 Which aspects of voltage or frequency Ride-through requirements that the IBR would be unable to meet and the capability of the hardware due to the limitation;

4.1.3 Identify the specific piece(s) of hardware causing the limitation;

4.1.4 Supporting technical documentation verifying the limitation is due to hardware that needs to be physically replaced or that the limitation cannot be removed by software updates or setting changes, and;

4.1.5 Information regarding any plans to remedy the hardware limitation (such as an estimated date).

4.2. Provide a copy of the information detailed in Requirement R4.1 to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA no later than 12 months following the effective date of PRC-029-1.

4.2.1 Any response to additional information requested by the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA shall be provided back to the requestor within 90 days of the request.

4.2.2 Provide a copy of the acceptance of a hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s).11

4.3. Each Generator Owner with a previously accepted limitation that replace the hardware causing the limitation shall document and communicate such a hardware change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the hardware change.

4.3.1 When existing hardware causing the limitation is replaced, the exemption for that Ride-through criteria no longer applies.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

Frequency exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments. Current technology does not appear to support being able to fulfill these requirements on a go forward basis.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Frequency exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Please see additional comments in Question #3.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports the comments provided by the NAGF which state: *"…recommends that PRC-029 be revised to allow for frequency ride through ("FRT") exemptions to address such limitations for legacy IBR facilities. Not including FRT exemptions will result in a standard that will make certan IBR legacy facilities automatically non-compliant when the standards becomes effective.* *Requirement R3 – the NAGF is concerned that legacy IBR facilities are not capable of meeting the 5 Hz/second maximum ROCOF or the 25-degree phase angle jump requirements. Therefore, FRT exemptions are necessary and need to be included in Requirement R3.* *Requirement R4.2.2 – the NAGF is unclear as to what the Compliance Enforcement Authority (CEA) acceptance for a IBR hardware limitation exemption will consist of. Will the CEA provide an email response confiming acceptance to the Generator Owner submitting the exemption? How are such exemptions to be submitted and to whom within the CEA organization?*	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see the response to NAGF.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	No
Document Name	
Comment	

Vistra supports comments made by AEP (Fultz)

Likes 0	
Dislikes 0	

Response

Thank you. Please see the response to AEP.

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

1. Requirement 2.1.3/2.2/2.5 - What does “other mechanisms” mean? Too vague.
2. Requirement 4.1.1 - change “facility #” to “facility unique identification number.”
3. Requirement 4.2 - “CEA” is not defined in first instance of the acronym in the document.
4. Multiple Requirements list several points of contact for notification (“associated” PC, TP, TO, RC, CEA). This seems like a very long list of contacts that would likely lead to unnecessary PNCIs. Can this list be reduced?

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

The usage of “other mechanisms” is to assure clarity that those are inclusive of requirements given outside of PRC-029-1; it is intended to prevent a GO from being non-compliant if required to operate differently that PRC-029-1.

The # has been changed as noted.

CEA has been defined in the first usage.

The list is consistent with entities who will be expected to be notified of limited capability (planners and operators) as well as the CEA for the limitation acceptance.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy does not agree with the current draft(3) of PRC-029-1.

FirstEnergy continues to request the DT consider changing PRC-029-1 Requirement R2, part 2.5, from 'Real Power' to 'Apparent Power'. To satisfy R2.5 as written, IBR sites would need to operate in static VAR control rather than automatic voltage control (adjusting VARs to control voltage). This would maintain a static power factor on the sites that would fail to provide effective voltage support due to manual intervention required to adjust VAR setpoint, not allowing for immediate response to voltage changes. This weakened response to voltage changes could result in less stable grid voltage, increasing potential for voltage trips, which does not align with the intent of the Standard. Changing this to 'Apparent Power' would make compliance more achievable while improving voltage support from IBR generators, enhancing IBR stability and reliability.

FirstEnergy also does not agree with the concept of 'Available Real Power' as used in R2.1.1 & R2.5 and defined in in footnotes 4 & 7 of Standard draft 3. Terminology/concepts critical for determining or maintaining compliance should be clearly defined in the NERC Glossary of Terms, not nested in a Standard footnote. For this term, specifically as it pertains to solar installations, the methods for measuring and approximating the 'Available' irradiance should be defined in detail as a Standard Attachment or preferably a Reliability Guideline. This guidance is required to create design specifications and ensure Owners/Operators consistently and uniformly quantify this resource for a given time and physical location. However, even with well-defined methods provided, it seems the ability of an Owner/Operator to definitively prove an exception in the case of solar would be challenging and difficult to audit; examples of evidence needed to properly justify an exception should be provided as guidance as well.

FirstEnergy also believes there could be a conflict between VAR-002 and PRC-029 for those IBR Resources meeting the applicability criteria of both Standards. VAR-002 requires generators to operate in automatic voltage control mode, adjusting reactive power output to control voltage. Adherence to PRC-029 R2.5 seems to directly conflict. This would require having alternative instructions from the TP/PC/RC/TOP, essentially granting an exception to one of the two Standards, to avoid a situation of non-compliance. Further clarification from the DT is warranted addressing the overlap/conflict between the two Standards and how an applicable IBR generator is to comply to both.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. Drafting teams are encouraged to use existing defined terms such as Real Power and Reactive Power when possible. R2.5 only applies when returning to the continuous operating region and has recovered from the mandatory (or permissive) operating region. The usage of footnotes to clarify a specific requirement are appropriate in PRC-029-1. Guidance is outside the scope of a Reliability Standard and an entity must be able consider their own facts and circumstances when seeking to comply. The usage of “other mechanisms” is to assure clarity that those are inclusive of requirements given outside of PRC-029-1; it is intended to prevent a GO from being non-compliant if required to operate differently that PRC-029-1.

Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	No
Document Name	
Comment	

1. "Removing Transmission Owners (TOs) from the applicability section places all accountability during voltage and frequency excursions on the IBR's Generator Owner (GO) regardless of the initial incident that starts the voltage or frequency excursion and regardless of who owns any impacted connecting equipment. This creates an inconsistency in compliance between PRC-024-4 and PRC-029-1." 2. "The new wording in Section 2.1.3 is unclear." 3. "Sections 2.1 and 2.2 are worded in a way that seems conflicting."

Likes 0	
Dislikes 0	

Response
Thank you for your comment. Transmission Owners have been removed from all milestone 3 and are not required to assure the ride-through capability of a GOs IBR. PRC-029-1 allows exceptions when needing to disconnect to clear a fault. Section 2 was reviewed and appears clear.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	

Comment
R1, R2 and R3 state, "Each Generator Owner shall ensure the design and operation is such…" Operation of the equipment is the GOP's responsibility, not the GO's. If the SDT's intention was regarding the design of the system, AEP recommends revising the language to instead state, "Each Generator Owner shall ensure the *operational design* is such…". AEP recommends removing the phrase "demonstrate the design of each facility" from the proposed standard and returning to the original event-based requirements. The phrase may prove difficult to fully comply with, as a Functional Entity would have to know the design of the collector system and parameters and run the models correctly to demonstrate this. Much of this needed information would need to

be provided by the manufacturer, which may require non-disclosure agreements.

There needs to be an exemption for system-related causes of ride-through failure. IBRs should be exempt from ride-through requirements in R1 through R3 if tripping or failure to ride through is attributable to any of the following:
1. Sub-synchronous control interaction or ferro-resonance involving series compensation confirmed by the TOP, RC, TP, or PC
2. Unstable behavior of other nearby IBRs or dynamic devices such as FACTS or HVDC confirmed by the TOP, RC, TP, or PC
3. System short circuit levels during contingencies below the level of IBR stable operation confirmed by the TOP, RC, TP, or PC
4. System-level transient or oscillatory instabilities confirmed by the TOP, RC, TP, or PC

AEP is concerned by the inclusion of the phrase “other mechanisms” in this standard, and recommend it be removed from Requirements 2.1.3, 2.2, and 2.5 as we believe it could be misinterpreted or misunderstood.

AEP believes the text “any response to additional information requested” in R 4.2.1 is confusing and should be clarified. AEP suggests it instead state “Additional information requested by the associated…”. In addition, Compliance Enforcement Authority should be spelled out in its entirety in its first use in the standard.

R4.2.2 states an obligation to “Provide a copy of the acceptance of a hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s).” AEP recommends that insight be provided in the Technical Rationale as to how the SDT envisions this acceptance process, and the timing thereof, would work.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The approach to PRC-029-1 is consistent with FERC Order No. 901 and the SAR assigned to the drafting team.

CEA has been spelled out in the first usage and R4 was modified for clarity.

The process for acceptance by the CEA will be determined through the CMEP process and is not within the scope of a Reliability Standard.

Brian Lindsey - Entergy - 1	
Answer	No
Document Name	
Comment	

M1: This seems more like a requirement than a measure for meeting the requirement.

R2, M2, M3 and R4: Duplicative of Mod-026 and MOD-027. Also, seems to be dependent on PRC-028 passing and sites having DDRs installed.

R2 is not clear. It seems to overlap significantly with VAR-002.

R2.5 While the IBRs can respond quicker than 1 second and should be able to retore active power to the pre-disturbance level within that time-frame it may be difficult to have enough historian capability to ensure proper evidence.

R3 No provisions for exemptions for frequency limitations.

R4.1 thru 4.2: Are we seeking approval from this large list of entities for an exemption or are we documenting the limitation that prevents from meeting requirement 1? If we have to get approval there is no requirement in this standard that require any of these entities to provide that approval. Recommend limiting who must be notified to just the TP or TP and RC. There needs to be a single point of contact instead multiple entities. The CEA should not play a role in the acceptance or denial of limitations. Standards Drafting Teams have no authority to create requirements that the CEA must adhere to therefore, there are no penalties to the CEA if they do not provide an acceptance.	
Likes 0	
Dislikes 0	

Response

Thank you for your comment.

Measures are not enforceable and are not requirements.

R2: The usage of “other mechanisms” is to assure clarity that those are inclusive of requirements given outside of PRC-029-1; it is intended to prevent a GO from being non-compliant if required to operate differently that PRC-029-1.

Frequency exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds.

The inclusion of additional planners and operators is consistent with the expectations within FERC Order No. 901.

The CEA is the appropriate entity to determine if the entity has met the requirements of R4. An entity who has submitted data per R4 to the CEA and is awaiting acceptance by the CEA, is still compliant with R4.

Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	No
Document Name	
Comment	

SMEs responded with the following comments:

1. "Removing Transmission Owners (TOs) from the applicability section places all accountability during voltage and frequency excursions on the IBR's Generator Owner (GO) regardless of the initial incident that starts the voltage or frequency excursion and regardless of who owns any impacted connecting equipment. This creates an inconsistency in compliance between PRC-024-4 and PRC-029-1."
2. "The new wording in Section 2.1.3 is unclear."
3. "Sections 2.1 and 2.2 are worded in a way that seems conflicting."

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

Transmission Owners have been removed from all milestone 3 and are not required to assure the ride-through capability of a GOs IBR. PRC-029-1 allows exceptions when needing to disconnect to clear a fault. Section 2 was reviewed and appears clear.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes

Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see the response to IRC SRC.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
The DT should cpnsider emphasizing the nature of the definition may not allow a single turbine or solar array to be lost in a System Disturbance (equates to failed "Ride-through" with loss).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Partial IBR trips are analyzed within PRC-030-1 and PRC-029-1 R2.5.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,Texas RE,NPCC,SERC,RF, Group Name SRC 2024	
Answer	Yes

Document Name	
Comment	

The SRC supports the addition of Part 4.2.2.:

4.2.2 Provide a copy of the acceptance of an hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s).

Likes 0	
Dislikes 0	
Response	

Thank you for your comment.

Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	
Comment	

The work and efforts of this standard drafting team are much appreciated. Thank you for considering EPRI comments on the previous drafts as submitted previously. The new Draft 3 appears to be improved regarding internal consistency and alignment with requirements specified in voluntary industry standards, for example, IEEE 2800-2022. However, further improvements and alignment could be considered as follows:

A. General comments:

- Aligned with the directives to NERC in FERC order 901, the draft PRC-029 standard and the Implementation Plan for Project 2020-02 propose that the requirements apply to all applicable IBRs upon the standard's revised effective date or the newly added phased-in compliance dates. Applicable IBRs include existing (Legacy) IBRs that are already in operation prior to the specified dates. Requirement R4 provides a path for each Generator Owner to request a limited and documented exemption of a legacy IBR from the voltage ride-through criteria specified in R1 and R2. According to the Implementation Plan of Project 2020-02, "[o]ther NERC Standards Development projects will be pursued to address ongoing identification and mitigation of any potential reliability impacts to the BPS for such exemptions." A similar exemption from Requirement R3 that specifies applicable IBR frequency ride-through criteria is not possible according to the draft standard.

- The proposed approach may require documentation of hardware limitations or reconfiguration for a significant number of legacy IBRs across North America. Neither the draft Technical Rationale nor the FERC record under RM22-12 present or cite sufficient technical evidence that supports this broad application of the proposed standard to existing IBRs in all applicable NERC regions.
- International experience has shown that documentation of hardware limitations to support exemption from, or the retroactive application of similarly stringent ride-through capability requirements on legacy IBRs are associated with significant uncertainties, potential technical and procedural challenges, and costs. Justification of similarly ambitious regulations enforced in other countries required the production of evidence like post-mortem disturbance analysis or case studies that *quantified* the potential impact of non-compliant existing IBRs on the bulk power system stability and reliability.[1],[2]
- Consequently, stakeholder concerns contribute to low approval rates for the draft PRC-029, possibly causing delays in moving the draft standard through the NERC process toward timely and effective enforcement for at least all new IBRs. Considering the approx. 2,600 GW of new IBRs in the interconnection queues across North America[3], these delays bear potentially significant risk for the BPS.
- Furthermore, the proposed revised effective date and newly added phased-in compliance date of the capability-based elements of Requirements R1, R2, and R3 as specified in the draft PRC-029 are different from the transition periods found in international practice of similarly ambitious rule changes for new and IBRs (see the comments on Implementation Plan below for further details).

- The term Inverter-based Resource (IBR) to which the draft standard is intended to apply refers to proposed definitions being developed under the Project 2020-06 Verifications of Models and Data for Generators. Although the new draft includes redlines that strike the explicit mentioning of VSC-HVDC transmission facilities that are dedicated connections for IBR to the BPS, the definition proposed by Project 2020-06 is sufficiently broad that it could cover such facilities. For further clarity on the scope and application of the proposed PRC-029 standard, it could be helpful to add a clarifying sentence or to copy parts of Footnote 2 that clarifies the location of the "main power transformer" in case of IBR connecting via a dedicated VSC-HVDC transmission facility into the terms section on page 2 of the standard.

- For the purpose of clarity, harmonization, and compliance of IBR across North America, proposed requirements could even further align with requirements that are testable and verifiable as specified in voluntary industry standards developed through an open process such as ANSI, CIGRE, IEC, or IEEE. The drafting team is encouraged to review these standards and where applicable further align, for example:
    - Requirement R1 and R2 relate to IEEE Std 2800™-2022, Clause 7.2.2 (Voltage disturbance ride-through requirements), with consideration of Clause 7.3.2.4 (Voltage phase angle changes ride-through) as a stated exception in R1.
    - Requirement R3 relates to IEEE Std 2800™-2022, Clause 7.3.2 (Frequency disturbance ride-through requirements), with consideration of Clause 7.3.2.3.5 (Rate of change of frequency (ROCOF) ride-through) as a stated exception in R3.
    - Measures M1–M3 relate to IEEE P2800.2 Draft 1.0a, Clause 5 (Type tests), Clause 6 (Validation procedures for IBR unit models and supplemental IBR device models), and Clause 7 (Design evaluations), Clause 8 (As-built installation evaluations), Clause 9 (Commissioning tests), Clause 10 (Post commission model validation), and Clause 11 (Post-commissioning monitoring).
    - Measure M4, additionally, relates to IEEE P2800.2 Draft 1.0a, Clause 12 (Periodic tests), and Clause 13 (Periodic verification).
- The draft standard does not specify grid conditions for which the specified ride-through requirements apply. During its lifetime, a plant may experience many different operational conditions, along with changes to the grid, and may fail to ride-through an event if the plant was operating in a grid condition vastly different from that which it was designed for. The standard could include an exception for such situations based on leading industry practices, or a requirement for the TP, PC, etc. to specify such an exception.
- IEEE 2800-2022 allows for an exception for "self-protection" when negative-sequence voltage is greater than specified duration and threshold within continuous operation region. There is no such exception in draft PRC-029. Such an exception may be necessary for type III wind turbine generator (WTG) based plants.
- Standard does not allow any flexibility for failure of ride-through resulting from misoperation of protection system. The misoperation of protection system may occur for many reasons over the life of a plant. For example, for a fault on a transmission system, if differential protection for the main step-up transformer misoperates due to environmental issues such as damage due to water from a leaking roof or animal intrusion, then plant would be considered out of compliance. If a synchronous machine based generating plant trips because of similar issue, it would not be out of compliance with PRC-024.
- Requirements R1–R4 call out both "design and operation". If the plant is designed to ride-through, then is it necessary to specifically call out and include IBR "operation" into the scope of PRC-029?
    - The inclusion of "operation" in PRC-029 would put a Generator Owner out of compliance with the standard whenever one of their IBR plants fails to ride-through real world disturbances, including incidents where failure of ride-through within the specified abnormal voltage and frequency conditions was beyond the GO's control.

- An alternative approach could be to narrow the scope of PRC-029 to require a Generator Owner to adequately *design* each IBR *to have the capability* to ride-through the specified abnormal conditions. The GO could then be further required by PRC-028 and PRC-030 to monitor IBR performance during operations and for real world events. If an IBR was found to have failed ride-through during operations, then PRC-030 could require the GO to identify the underlying issues and to take corrective action.

B. Ride-through definition

- Consider adopting definition from IEEE 2800, which is from IEEE 1547, and well understood by the industry.

C. Requirement R1:

- Requirement calls out "design and operation". If the plant is designed to ride-through then is it necessary to specifically call out "operation"?
  - The Reliability Standard PRC-006, Requirement R3, requires PC to develop UFLS program. Several assumptions are made here. If an event occurs, then R11 requires assessment of an event and if deficiency in UFLS program is identified then PC is required to consider deficiencies in R12. If UFLS program was deficient then PC is not out of compliance with R3 (or any other requirements in the standard). This is a good-faith approach: Design UFLS program and if actual event shows deficiency in UFLS Program then fix it. No compliance issues, as far as UFLS program was designed per Requirement R3.
  - Same approach could be taken in PRC-029, where R1 could require that plant is designed to ride-through specified voltage disturbance. The PRC-028 and PRC-030 then requires monitoring of plant performance and take corrective actions when necessary.
  - The same approach could be extended to requirements R2 and R3.
- If IBR operation remains within the scope of PRC-029, then consider revising the beginning of the sentence as following for better readability: *Each Generator Owner shall design and operate each IBR to meet or exceed Ride-through requirements…*
  - The same changes could be extended to requirements R2 and R3.

D. Requirement R2

- Refer to comments on R1 that could be extended to requirement R2.

E. Requirement R2, Part 2.1

- Why is it necessary to specify a performance requirement when voltage is in the continuous operation region? The standard remains silent on performance expectation for frequency ride-through requirements. For performance requirement for voltage ride-through mandatory operation region is also very brief. The intent of this standard is to focus on ride-through during voltage and frequency disturbances. If there is a desire to address performance then one option could be to simply state that performance shall be as specified by TP, PC, etc. That is in Part 2.1.3 anyway.
- Part 2.1.2: remove “and according to its controller settings”. It is not incorrect but “according to its controller settings” inherently apply to all performance requirements.
- Part 2.1.3: this requirement in IEEE 2800 was necessary and was tied to reactive power capability requirement as shown in Figure 8 of IEEE 2800. Given PRC-029 does not include reactive power capability requirements, perhaps PRC-029 could remain silent.

F. Requirement R2, Part 2.2

- Part 2.2 applies at the high-side of the main power transformer. The IBR is required to exchange current, up to the maximum capability. How is the “maximum capability” of an IBR determined? There could be some explanation, perhaps with examples, in the technical rationale document.
- The phrase “provide voltage support on affected phases during both symmetrical and unsymmetrical voltage disturbances” is confusing.
    - It is understood that intent is to require to inject “unbalanced current” or “negative-sequence” current during asymmetrical faults. However, as written, injection of balanced reactive current into an unbalanced fault meets the requirement to provide voltage support on affected phases, in addition to unaffected phase. The standard does not prohibit voltage support on unaffected phases. The voltage support on unaffected phase is usually problematic. But the requirement, as written, does not prohibit this.

- During a L-G fault, current in a faulted phase is dependent on transformer winding configuration. Does this requirement, unintentionally, specify specific transformer configuration?
- During mandatory operation, voltage is abnormal and could be almost zero for close-in faults. As such, “current” over “power” is more appropriate. Power in faulted and unfaulted phases could be different as well. Replace real and reactive power with active (real) and reactive current respectively.

G. Requirement R2, Part 2.3.1

- Per language in attachment 1, permissive operation is allowed when line-to-ground or line-to-line voltage is below 10%. But per Part 2.3.1, IBR is required to restart current exchange when positive-sequence voltage enters continuous or mandatory operation region. This is conflicting. For example, for a line-to-ground fault on high-side terminals of main power transformer, the positive-sequence voltage would be more than 10%, i.e., in the mandatory operation region.

H. Requirement R2, Part 2.4

- The intent of this requirement is understood. However, if there are multiple plants in the area, then one plant misbehaving may cause overvoltage on high-side terminals of the main power transformer of other plants in the area. Also, the post-fault dynamics greatly depend on system operating condition (peak, shoulder, off-peak, etc.) along with transmission outages, status of capacitor banks, etc. The Generator Owner usually does not have system data to evaluate post-fault system dynamics and to determine if plant’s behavior is or not a contributing factor to overvoltage.

I. Requirement R3

- Refer to comments on R1 that could be extended to requirement R3.
- The proposed frequency ride-through requirement is more stringent than the applicable requirement in IEEE Std 2800-2022. The justification provided in the technical rationale is based on engineering judgement with no provided substantiating studies. Furthermore, the PRC-006 requires the design of UFLS program to keep frequency withing certain bounds. Requiring IBRs to ride-

through a slightly more frequency deviation compared to frequency deviation band allowed in PRC-006 seems reasonable. However, the proposed frequency ride-through requirement is much more stringent. Consider aligning with IEEE Std 2800 frequency ride-through requirement as a minimum requirement and let regions specify more stringent requirements where justified.

- The standard does not allow exception for frequency ride-through requirements. While the physical strain on legacy IBR plants to ride-through frequency disturbances may be less significant compared to the strain during voltage ride-through, the capabilities of legacy IBR hardware (including wind-turbine generators, inverters, transformers, and auxiliary equipment like fans and pumps for cooling, if present) are, at best, uncertain. For plants in commercial operation before the effective date of this standard, installed equipment may not have been tested to the specified frequency ride-through capability and that could make determining if a legacy IBR plant would be able to ride-through proposed frequency ride-through requirements challenging.
    - The SDT points to directive in FERC order 901 and states that order 901 does not allow exception for frequency ride-through. However, order 901 does not require frequency ride-through requirements as stringent as the ones proposed.
    - It is also not clear to us from the record in RM22-12 whether FERC intentionally limited the exemption from ride-through to only voltage ride-through, and on what technical grounds the exemption did not also include frequency ride-through.[4],[5],[6]
- Footnote 9 could be simplified as following: *The ROCOF is an average rate of change of frequency over an averaging window of at least 0.1 second.*

J. Requirement R4

- We re-iterate the following observations related to the Effective Date and Phased-in Compliance Dates stated in the Implementation Plan of the project, as previously offered in our EPRI comments on the initial draft of PRC-029:

o Aligned with the directives to NERC in FERC order 901, the draft proposes that all requirements specified in PRC-029 apply to all applicable IBRs upon the standard's effective date, including Legacy IBRs that were already in operation prior to that date. This approach may require reconfiguration or documentation of hardware limitations for a significant number of existing IBRs across North America. In some cases, for example where the original equipment manufacturer (OEM) of hardware used in Legacy IBRs has gone out of business, or the OEM has ceased to support a legacy hardware product line, documentation of hardware limitations and development of models accurately representing Legacy IBR performance may be challenging. Additional exemptions to address these challenges could be included in R4 of the draft standard or the implementation plan.

o One example for an alternative approach to the one proposed in the draft PRC-029 could be that TOs and reliability coordinators were to discern on a regional or case-by-case basis about the application of PRC-029 to Legacy IBRs, preferably based on technical evidence like case studies assessing and quantifying the potential BPS reliability impacts from Legacy IBR in their regions.[7] If documentation of Legacy IBR hardware limitations was not available, worst-case assumptions could be made in these case studies. If such studies indicated a viable reliability risk, R4 could be applied to selected or all Legacy IBRs. This could produce documentation of hardware limitations to refine study assumptions to produce more realistic case study results. If refined results still indicated a viable reliability risk, R1-R3 could be applied to Legacy IBRs selectively.

- We refer to our questioning of FERC's intentionality with not including an exemption for frequency ride-through capability per our comments on Requirement R3 above.
- For further comments on the Effective Date and Phased-in Compliance Dates refer to below comments on the Implementation Plan.
- Parts 4.1 and 4.2 refers to exemption for a plant but part 4.3 refers to hardware in plant. If few of many wind-turbine generators in a plant are replaced, then plant still has limitation because most of the wind-turbine generators still have limited capability. Perhaps some clarification could be added that if "all hardware with documented capability limitation" is replaced, only then an exemption for a legacy IBR would not apply any longer.

K. Violation Risk Factors

- The language for the assignment of a VRF to Requirement R4 in the draft standard is truncated. Consider revising to: *[Violation Risk Factor: Lower]*
- Each Generator Owner is required per Requirement R4 to identify, document, and communicate about legacy IBRs that have hardware limitations related to the voltage ride-through criteria specified in R1 and R2. Why is a VRF of "Lower" assigned to R4 and not a VRF of "Medium"? Could the uncertainty related to the capability and performance of legacy IBRs associated with a violation of R4 (a requirement that is administrative in nature and a requirement in a planning time frame) by a Generator Owner not, under the abnormal conditions, be expected to directly and adversely affect the electrical state or capability of the Bulk-Power System, or the ability to effectively control the Bulk Power System?

L. Violation Severity Levels

- R1, R2, and R3: The lower VSL for each of these requirements is for failure to demonstrate the design capability to ride-through. There are two reasons for which this could arise:

(1) Plant is capable to ride-through but is not demonstrated in design evaluation or interconnection studies.

(2) Plant is not capable to ride-through and that is demonstrated in design evaluation or interconnection studies.

- Reason (1) is not a problem for grid reliability, it is just that studies are not adequate to demonstrate ride-through capability, and hence lower VSL is justified. But reason (2) is not any different from a case in severe VSL where an entity fails to demonstrate that IBR adhered to ride-through requirements (based on actual system disturbance event data).
- The VSLs could be rephrased to read:
  - Lower VSL: *The Generator Owner failed to produce adequate evidence demonstrating for each applicable IBR that it was designed to Ride-through in accordance with …*
  - Severe VSL: *The Generator Owner either produced evidence demonstrating for any of their applicable IBR that it was not adequately designed to adhere to Ride-through, or the Generator Owner failed to produce evidence of actual disturbance monitoring data for a specific event that demonstrate each applicable IBR adhered to Ride-through requirements in accordance with …*

M. Attachment 1

- Tables 1 and 2 are inconsistent. Table 1 states “>= 1.10” whereas Table 2 states “>1.10”.
- Clarify that cumulative window, for voltage band where ride-through duration is 1800-second, is 3600-second. Also, consider clarifying that 1800-second ride-through duration is only applicable to nominal voltages other than 500 kV.
- Numbered item #3: states that applicable voltage is “… on the AC side of the transformer(s) that is (are) used to connect…..”. Both sides of transformer are AC, one is on DC-AC converter side and another on AC grid side. As written, voltage on either side of transformer is applicable. Please clarify that applicable voltage is on AC “grid” side of the transformer.
- Numbered item #5: Consider revising as following - *The applicable voltage for Tables 1 and 2 is identified as the voltage max/min of phase-to-[strike: neutral] [add: ground] or phase-to-phase fundamental [add: frequency] root mean square (RMS) voltage at the high-side of the main power transformer.*

- Numbered item #7: The interpretation of ride-through curves/points needs further clarification. Would a wind-based IBR plant be required to ride-through an event where at t=0 voltage drops from nominal to zero, then @t=0.16 s voltage rises to 25%, @t=1.2 s voltage rises to 50%, @t=2.5 s voltage rises to 70%, @t=3 s voltage rises to 90%? The item (8) is also tied to item (12), where a combined "area" is stated. Does must ride-through zone represent an "area" (represented by deviation in voltage multiplied by time duration)? Consider adding a few examples in the technical rationale.
    - Note that IEEE 2800-2022, informative Annex D, Section D.1 (Interpretation of voltage ride-through capability requirements specifies) states that the interpretation used in the standard is a "voltage versus time curve." However, the same Annex includes a Figure D.4 that intends to show "a realistic and complex trajectory of a voltage during a disturbance" for which the informative annex then further states that an IBR plant "is required to ride through," effectively interpreting the IEEE 2800-2022 ride-through curves as a "voltage versus time envelope." Thus, there seems to be some ambiguity in IEEE 2800-2022 as to how to interpret its ride-through curves, a finding that could be considered and resolved in a potential future revision or amendment of IEEE 2800.
    - If the voltage ride-through requirements proposed in Attachment 1 were to be specified or interpreted as a "voltage versus time envelope,", and considering that an unknown number of IEEE SA balloters that voted affirmatively on IEEE 2800-2022 may have interpreted the IEEE 2800-2022 requirements as the less stringent "voltage versus time curves" explained in Annex D of the standard, the proposed PRC-029 could be perceived as more stringent than IEEE 2800-2022.
    - Adding a few examples in the technical rationale could help clarify the correct interpretation of the voltage ride-through curves specified in Attachment 1.
- Numbered item 10: Please clarify if this statement applies to protection applied to high side of main power transformer only OR everywhere in the plant.

N. Attachment 2:

- Table 3: To be consistent with other frequency thresholds, could "> 61.2" be ">= 61.2" instead. If so, range for continuous operation then be "< 61.2 and > 58.8".
- Consider adding a statement that frequency ride-through requirements apply only when voltage is in the must ride-through zone.
- Numbered item 3: What is meant by control settings? Is the intent to state protection settings instead?

O. Implementation Plan

- The proposed revised effective date and newly added phased-in compliance date of the capability-based elements of Requirements R1, R2, and R3 as specified in PRC-029-1 *for primarily new IBRs* of,
  - "the first day of the first calendar quarter that is *twelve months [emphasis added by EPRI]* after" either "the effective date of the applicable governmental authority's order approving" or "the date the standard is adopted by the NERC Board of Trustees" for (primarily new) Bulk Electric System IBRs, and
  - "until the later of: (1) January 1, 2027; or (2) the effective date of the standard" for (primarily new) Applicable Non-BES IBRs

are different from transition periods found in international practice of similarly significant rule changes for new IBRs. Examples for reference include, but are not limited to:

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  - (European) Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators, Article 72 (Entry into force) states, "the requirements of this Regulation shall apply from *three years [emphasis added by EPRI]* after publication." [8]
  - German Government, "Verordnung zu Systemdienstleistungen durch Windenergieanlagen (Systemdienstleistungsverordnung – SDLWindV) (Ordinance for Ancillary Services of Wind Power Plants (Ancillary Services Ordinance - SDLWindV),"[9]

- Mandatory requirement for new wind power plants to meet specified requirements by March 31, 2011, i.e., *19 months* after ordinance entered into force.

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  - ERCOT, "Issue NOGRR245. Inverter-Based Resource (IBR) Ride-Through Requirements. Report of Board Meeting on June 18, 2024,"[10] and ERCOT, "Nodal Operating Guide Revision Request (NOGRR) 245, Inverter-Based Resource (IBR) Ride-Through Requirements. ERCOT Update," August 8, 2024."[11]

- All new IBRs with a Standard Generation Interconnection Agreement (SGIA) after August 1, 2024, i.e., *immediately once the NOGRR enters into force* (subject to change until ERCOT board approval and until there is a non-appealable Public Utility Commission of Texas (PUCT) final order is in place)

- Extension of exemption from requirements new IBRs with a Standard Generation Interconnection Agreement (SGIA) after August 1, 2024, does not exceed December 31, 2028, i.e., *4 years and 4 months* (subject to change until ERCOT board approval and until there is a non-appealable Public Utility Commission of Texas (PUCT) final order is in place)

- The proposed revised effective date and newly added phased-in compliance date of the Requirement R4 as specified in PRC-029-1 *for primarily legacy IBRs* of,
    - "the first day of the first calendar quarter that is *twelve months [emphasis added by EPRI]* after" either "the effective date of the applicable governmental authority's order approving" or "the date the standard is adopted by the NERC Board of Trustees" for (primarily legacy) Bulk Electric System IBRs, and
    - "until the later of: (1) January 1, 2027; or (2) the effective date of the standard" for (primarily legacy) Applicable Non-BES IBRs

are either not applicable, or—for re-configurations that do not require replacement of hardware—comparable, or—for retrofits that do require replacement of hardware—they are different from transition periods found in national and international practice of similarly significant retro-active enforcements for legacy IBRs. Examples for reference include, but are not limited to:

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    - (European) Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators, Article 4 (Application to existing power-generating modules) states, [12]

- "Existing power-generating modules are not subject to the requirements of this Regulation, except where: … ."

- "For the purposes of this Regulation, a power-generating module shall be considered existing if:

· (a) it is already connected to the network on the date of entry into force of this Regulation; or

· (b) the power-generating facility owner has concluded a final and binding contract for the purchase of the main generating plant by *two years [emphasis added by EPRI]* after the entry into force of the Regulation.

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    - German Government, "Verordnung zu Systemdienstleistungen durch Windenergieanlagen (Systemdienstleistungsverordnung – SDLWindV) (Ordinance for Ancillary Services of Wind Power Plants (Ancillary Services Ordinance – SDLWindV))," [13]

- Financial incentive for voluntary retrofits of legacy wind power plants between July 11, 2009, and January 1, 2011, i.e., *1.5-years*.

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    - German Government, "Verordnung zur Gewährleistung der technischen Sicherheit und Systemstabilität des Elektrizitätsversorgungsnetzes (Systemstabilitätsverordnung - SysStabV) (System Stability Regulation – SysStabV)),"[14]

- Mandatory requirement for reconfiguration of legacy IBRs and distributed energy resources (DERs) larger than 100 kW by August 31, 2013, i.e., *13 months* after ordinance entered into force.

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    - ERCOT, "Issue NOGRR245. Inverter-Based Resource (IBR) Ride-Through Requirements. Report of Board Meeting on June 18, 2024,"[15] and ERCOT, "Nodal Operating Guide Revision Request (NOGRR) 245, Inverter-Based Resource (IBR) Ride-Through Requirements. ERCOT Update," August 8, 2024."[16]

- Mandatory requirement for legacy IBRs with an SGIA executed prior to August 1, 2024 to maximize the performance of their protection systems, controls, and other plant equipment (within equipment limitations) to achieve, as close as reasonably possible, the capability and performance set forth in IEEE 2800-2022 no later than December 31, 2025, i.e., *17 months* after NOGRR enters into force.

- Extension of exemption from requirements for legacy IBRs with a Standard Generation Interconnection Agreement (SGIA) prior to August 1, 2024, does not exceed December 31, 2027, i.e., *3 years and 4 months* (subject to change until ERCOT board approval and until there is a non-appealable Public Utility Commission of Texas (PUCT) final order is in place)

- The first use of the word "or" in the sentence under the section Effective Date and Phased-in Compliance Dates, PRC-029-1 Phased-in Compliance Dates, Requirement 4, Applicable Non-BES IBRs on page 5 of the Implementation Plan could be replaced for clarity with the word "for" to then read: *Entities shall not be required to comply with Requirement R4 for their non-BES IBRs until the later of: (1) January 1, 2027; or (2) the effective date of the standard.*

P. Technical Rationale

- IEEE Std 2800™-2022, a voluntary industry standard for *Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems* is mentioned in the Technical Rationale document for PRC-029-1 but not cited properly. In all instances where the document refers to that IEEE standard, referencing could be improved by following our guidance offered below. Where appropriate, reference to and proper citation of IEEE P2800.2, an active IEEE Standards Association project for developing of a *Recommended Practice for Test and Verification Procedures for Inverter-based Resources (IBRs) Interconnecting with Bulk Power Systems*, may serve as an additional reference.
    - Suggested referencing of IEEE Std 2800™-2022:

- For the initial citation within any document, we suggest citing the standard as follows: IEEE Std 2800™, IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems

- Subsequent mentions of the standard could refer to it as: IEEE 2800

-
    - Similar guidelines could be applied to IEEE Std 2800.2™:

- We recommend citing the standard in full on first reference as: IEEE P2800.2, Draft Recommended Practice for Test and Verification Procedures for Inverter-based Resources (IBRs) Interconnecting with Bulk Power Systems

- Followed by subsequent mentions as: IEEE P2800.2

- Considering the explicit statements in the "PRC-029-1_Technical_Rationale" document about the intended alignment with IEEE Std 2800™-2022 requirements in formulating the technical content of PRC-029-1 by the drafting team, references to specific clauses of IEEE Std 2800™-2022 could provide more clarity to industry stakeholders about which parts of the IEEE standard the PRC-029-1 aims to incorporate. It may also be helpful to identify areas where they are not aligned. Refer to the examples in our general comments above.
- IEEE 2800-2022 may not be the only industry standard with scope that overlaps with the proposed PRC-029 standard. ANSI and CIGRE currently may not have related standards. While IEC does have standards and technical specifications with related scope, these documents tend to be less specific in their technical requirements compared to IEEE standards like IEEE 2800-2022.[17]

Q. Justifications

- The table for "VRF Justifications for PRC-029-1, Requirement R3" on page 11 of the Justifications lists a Proposed VRF of "Lower"; but the draft PRC-029 standard assigns R3 a "[Violation Risk Factor: High]". Consider resolving inconsistency across the two documents.
- Refer further to the comment on the VRF assignment for Requirement R4 above.

[1] Grid Codes for Interconnection of Inverter-Based Distributed Energy Resources by Country: Recent Trends and Developments. EPRI. Palo Alto, CA: November 2014. 3002003283. [Online] https://www.epri.com/research/products/000000003002003283 (last accessed, January 24, 2023)

[2] Dispersed Generation Impact on CE Region Security: Dynamic Study. 2014 Report Update. European Network of Transmission System Operators for Electricity (ENTSO-E), ENTSO-E SPD Report, Brussels, Belgium: December 2014. [Online] https://eepublicdownloads.entsoe.eu/clean-documents/Publications/SOC/Continental_Europe/141113_Dispersed_Generation_Impact_on_Continental_Europe_Region_Security.pdf (last accessed, January 24, 2023)

[3] LBNL (2024) [Online] https://emp.lbl.gov/generation-storage-and-hybrid-capacity

[4] E-1-RM22-12-000.pdf [Online] https://www.ferc.gov/media/e-1-rm22-12-000 (last accessed, August 6, 2024)

[5] 20230206-5094_ACP-SEIA IBR NOPR comments (Final).pdf [Online] https://elibrary.ferc.gov/eLibrary/filedownload?fileid=49DB8845-A3E3-CEEA-A6D8-86289C500000 (last accessed, August 6, 2024)

[6] E-2-RM22-12-000.pdf [Online] https://www.ferc.gov/media/e-2-rm22-12-000 (last accessed, August 6, 2024)

[7] EPRI is currently working on case studies relevant to these topics and is also aware of others doing similar work.

[8] ENTSO-E: Requirements for Generators. [Online] https://www.entsoe.eu/network_codes/rfg/ (last accessed, August 6, 2024)

[9] Federal Law Gazette I (no. 39) (2009): 1734–46. [Online] https://www.clearingstelle-eeg-kwkg.de/gesetz/695 (last accessed, August 6, 2024)

[10] ERCOT, "Issue NOGRR245. [Online] https://www.ercot.com/mktrules/issues/NOGRR245 (last accessed, August 9, 2024)

[11] ERCOT, "Nodal Operating Guide Revision Request (NOGRR) 245, Inverter-Based Resource (IBR) Ride-Through Requirements. ERCOT Update," August 8, 2024 [Online] https://www.ercot.com/calendar/08082024-NOGRR245-_-Review-of (last accessed, August 9, 2024)

[12] Ref. Footnote 10

[13] Federal Law Gazette I (no. 39) (2009): 1734–46. [Online] https://www.clearingstelle-eeg-kwkg.de/gesetz/695 (last accessed, August 6, 2024)

[14] Federal Law Gazette I (no. 40) (2012): 1635. [Online] https://www.gesetze-im-internet.de/sysstabv/BJNR163510012.html (last accessed, August 6, 2024)

[15] Ref. Footnote 16

[16] Ref. Footnote 17

[17] Example IEC standards and technical specifications with related scope may include IEC 61400-27, IEC 62934:2021, IEC TS 63102:2021, and IEC TR 63401-4:2022.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Frequency exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds.

Regarding VSC-HVDC equipment for a dedicated connection to IBR, please see PRC-028-1 for the requirements regarding when disturbance monitoring equipment and data is needed. Grid conditions are not within scope of this project and may be pursued in future revisions with supporting technical information. IEEE 2800-2022 was not developed through the Standards Development process, cannot be adopted by NERC, nor are mandatory and enforceable requirements. Future revisions to PRC-029-1 may be pursued with supporting technical information to substantiate the reliability need. The scope of ride-through expectations are consistent with FERC Order No. 901 and the scope of the SAR assigned to the drafting team. See responses to Q1 regarding the definition. “Ensuring the operation” is consistent with a GOs ownership responsibilities and they may not be the GOPs in all instances. Additional performance guidance may continue to be pursued and is not necessary for Reliability Standards. Voltage support on unaffected phases is not required. R2 does not set transformer configurations as described. R2 uses Real and Reactive Power and not specify current performance. Note 5 states: The applicable voltage for Tables 1 and 2 is identified as the voltage max/min of phase-to-neutral or phase-to-phase fundamental root mean square (RMS) voltage at the high-side of the main power transformer. PRC-030 details the analytical responsibilities and not PRC-029. Frequency exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds. The risk factor language in R4 has been corrected. VRF are set in accordance with FERC Guidelines – see VSL/VRF Justifications for more detail. Recommended usage of “primarily new” would add ambiguity to comply.

Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	Yes
Document Name	
Comment	
PNM agrees with the comments of EEI.	

Likes 0	
Dislikes 0	

Response

Thank you. Please see the response to EEI.

Nick Leathers - Ameren - Ameren Services - 3 - SERC

Answer	Yes
Document Name	

Comment

Ameren recommends that the drafting team clarify the phrase "current block mode." Additionally, there is some concern that the technical requirements are so rigid that it might become challenging for utilities to implement a cost effective solution for the entity and customers. Additionally, Ameren supports the responses from both EEI and NAGF for this question.

R1, bullet point #2:

R1 suggests that we have to set protection so that we do not trip until capabilities are exceeded, which is not how Ameren sets protection. Ameren sets protection systems to operate before capabilities of equipment are exceeded. In addition, engineers should be setting relays per capabilities of equipment to prevent damage and to maximize their capability. We do not suggest using a generic capability when equipment may have higher capabilities. We suggest replacing the second bullet with the following and removing the last bullet.

"The applicable in-service protection system devices are set to operate to isolate or de-energize equipment in order to limit or prevent damage when the voltage or Volts per Hz (V/Hz) at the high-side of the main power transformer exceed accepted equipment capabilities in accordance with requirement R4; or"

Then add a footnote:

"If the Volts per Hz (V/Hz) withstand capability of the main power transformer is not available for an existing facility, then the applicable in-service protection system may be set to isolate or de-energize equipment if the volts per Hz at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per-unit for longer than 2 seconds"

R4, 4.1.2: In Ameren's experience, manufacturers are unwilling to share hardware capabilities on the inverter and claim it is proprietary or some other reason. We suggest a re-write of 4.1.2 to add an exclusion such as the following: "...If the Functional Entity has requested the capability of the hardware limitation, but the manufacturer will not provide the capability, the Functional Entity must provide evidence that they have made the effort to request this information from the manufacturer and provide this in lieu of the capability." Ameren requests the SDT to provide 2 years to verify compliance with R1, R2, R3 and R4 of the standard since the requirements are extensive.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The DT believes usage of current block mode is generally understood. The DT agrees that protection systems and controllers should be set in accordance with their physical capabilities. PRC-029-1 specifies minimum performance requirements. Additional language has been included concerning "proprietary information".	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you.	
Greg Sorenson - Greg Sorenson On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Thank you.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Thank you.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal	

Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	

MISO supports the addition of Part 4.2.2.:

4.2.2 Provide a copy of the acceptance of an hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s).

Likes 0	
Dislikes 0	
Response	
Thank you.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	

Southern Company appreciates the work of the SDT but would like to offer the follwing changes for consideration:

- There is a risk that changes to the IBR definition under Project 2020-06 may alter the definition for that contained in PRC-029, thus complicating standard implementation.
- Without providing technical justification, a FRT curve is more stringent than IEEE2800. In addition, industry has not been provided with any technical studies justifying the need for the proposed 6-second FRT bands. Southern Company recommends that the SDT align the FRT requirements with IEEE 2800. Individual Regions should be allowed to adopt more stringent FRT standards based on their respective system needs and resource capabilities.
- There is no technical justification for **No FRT** exemptions. (other than the "Regulatory Rationale" provided from FERC 901 Order). Section 215(d)(2) of the FPA requires FERC to give "due weight" to the technical expertise of the ERO when evaluating the content of a proposed Reliability Standard or modification to a Standard.
- The ROCOF requirement may be infeasible for certain legacy IBRs that are unable to disable ROCOF protection and distinguish between fault and non-fault conditions.
- Table 1 and 2 footnote 6 states that the voltage ride through charts are only valid when frequency is within the "must Ride-through zone" as specified in Figure 1 of Attachment 2. The SDT should add a similar footnote to Attachment 2 Table 3 FRT table stating that the frequency ride through charts are only valid when voltage is within the "must Ride-through zone". Illustrated in the Voltage Ride-through figures.
- In the Implementation Plan, Southern Company recommends extending the capability due date from 12 months of effective date of standard to 18 – 24 months due to expected complexity of solution development and deployment.

Likes 0	
Dislikes 0	

Response

Thank you.
The definition for IBR has passed and is used exclusively in this draft.
Frequency exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds.

Expected Ride-through performance during a frequency and voltage excursion necessitates requiring compliance with frequency Ride-through requirements.

Extension of implementation is not substantiated. A GO would be required to provide such documentation 12 months following the effective date, which is 12 months following the approval of PRC-029-1.

Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	
Document Name	
Comment	
NRG agrees with and refers the SDT to the EPSA comments.	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see the response to EPSA.	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE has the following clarifying comments on PRC-029-1:

- Texas RE recommends correcting Requirement R2 subpart 2.3.1:

2.3.1 If a **an** IBR enters current blocking mode, it shall restart current exchange in less than or equal to five cycles of positive sequence voltage returning to a continuous operation region or mandatory operation region

- In Requirement Part 4.1.1, Texas RE recommends changing “facility #” to “facility unique identifier” or “facility unique number”.

• Texas RE recommends Compliance Enforcement Authority (CEA) should be spelled out in Requirement R4 subpart 4.2 since it is the first time seeing that term in the requirement language.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The article “an” has been corrected as well as the # in 4.1.1. CEA has also been spelled out.	

3. Provide any additional comments for the Drafting Team to consider, if desired.

Bruce Walkup - Arkansas Electric Cooperative Corporation - 6

Answer	
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Thank you.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Thank you.

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	

Section 4: Applicability:

4.2 is not aligned with the PRC-028. The DT should consider the alignment of the applicability section between all IBR standards.

1) It is not clear what “The Elements associated with..” means in 4.2.1. Does it mean power system elements?

R2:

The new wording in Section 2.1.3 is unclear.

MH recommends it be changed to "Prioritize Real Power or Reactive Power delivery when the voltage is less than 0.95 per unit, the voltage is within the continuous operating region, and the IBR cannot deliver both Real Power and Reactive Power due to a current limit or Reactive Power limit unless otherwise specified through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator."

R3:

MH is still concerned with the lack of provisions for exemptions for frequency limitation (RoCoF) that may put some of the legacy IBR in a non-compliant state and may require a costly upgrade to meet R3 requirements.

MH recommends the following:

Extending the implementation date for R3 for legacy IBR to 18 months

or/and

Lowering the RoCoF for legacy IBR from 5 Hz /second to 3Hz/ second

R4:

The CEA is not a defined NERC term in the Glossary of Terms Used in NERC standard list, MH recommends spelled out Compliance Enforcement Authority (CEA) in Requirement R4 subpart 4.2 since it is the first time seeing that term in the requirement language. Attachment #1: MH agrees with removing the previous figures 1 and 2 from attachment # 1 but we recommend adding at least three voltage waveform examples into TR to illustrate how the Table 1 and 2 should be used to determine the compliance with voltage ride through TR: More information should be added to some frequency waveform examples in TR to illustrate how to calculate the RoCoF	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The applicability sections have been aligned. Frequency exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds. CEA has been spelled out. The figures in attachment 1 were removed to prevent confusion with setting curves (like PRC-024).	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	

Comment	
Tri-State agrees with the additional comments provided by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the response to MRO NSRF.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	
Dominion Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the response to EEI.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	
Document Name	
Comment	

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

AZPS supports the following comments that were submitted by EEI on behalf of its members: EEI offers the following additional comments on the proposed 3rd draft of PRC-029-1: · EEI does not support the inclusion of the phrase "The Elements associated with" as contained in the Facilities Section (4.2.1). The inclusion of this phrase expands the scope in ways that are unclear creating unnecessary compliance confusion. · Bullet 1 under Requirement R1 is unnecessary and should be deleted, noting that facilities are never obligated to stay connected to a fault. · EEI asks that the DT provide additional clarity to Requirement R4, subpart 4.2.2 noting that there is insufficient clarity regarding what is needed to support a hardware limitation and what the deadline is for the submission of a limitation.	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the response to EEI.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy agrees with and supports submitted EEI Additional Comments.	
Likes 0	
Dislikes 0	
Response	

Thank you, please see the response to EEI.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
none	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	
Document Name	
Comment	
The language in **Section 4, Applicability** does not match the language used in the latest proposed version of PRC-028-1. Although the language in PRC-029-1 is cleaner and preferred, it is not quite clear what is meant by the inclusion of the words "The Elements associated with" in Section 4.2.1. These words are unnecessary. SMUD would prefer that the drafting team delete these words and change Section 4, Applicablity to the language below. The language used in Section 4, Applicability for the currently proposed PRC-028-1, PRC-029-1 and PRC-030-1 should match. This change is non-substantive and could be made in the final ballot.	

The existing language in PRC-029-1 (and PRC-030-1) is as follows:

4.1 Functional Entities:

4.1.1. Generator Owner

4.2 Facilities:

4.2.1. ***The Elements associated with*** (1) Bulk Electric System (BES) IBRs; and (2) Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

The existing language in PRC-028-1 is as follows:

4.1. Functional Entities:

4.1.1. Generator Owner that owns equipment as identified in section 4.2

4.2. Facilities:

4.2.1 BES Inverter-Based Resources

4.2.2 Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV

SMUD’s preferred language in PRC-029-1 Section 4, Applicability is as follows:

4.1 Functional Entities:

4.1.1. Generator Owner

4.2. Facilities: 4.2.1 BES Inverter-Based Resources 4.2.2 Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. SMUD also agrees with the comments submitted by the MRO NSRF on Requirements R2, R3, R4, and Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The applicability sections have been aligned. Please see the responses to MRO NSRF.	
Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	
Document Name	
Comment	
NV Energy agrees with the NSRF comments especially on the lack of exceptions for legacy IBR systems (R3)	
Likes 0	
Dislikes 0	
Response	

Thank you, please see the response to MRO NSRF.	
Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
1. We believe NERC should coordinate the Implementation Plans for the three standard development projects associated with Milestone 2 of its work plan to address the directives within FERC Order No. 901. This would give most Generator Owners one set of compliance implementation dates to track. The phased-in compliance dates should align with those proposed under NERC Standard Development Project 2021-04, Reliability Standards PRC-002-5 and PRC-028-1, as those dates have been well vented across industry. As that project has proposed for some Generator Owners, this can be as much as within three (3) calendar years of the standard's effective date for 50% of those Generator Owners' BES Inverter-Based Resources. Then the rest of their BES Inverter-Based Resources must be compliant by January 1, 2030. The SDT Project 2021-04 SDT made similar simplifications for other Generator Owners with future IBRs yet to commission and for Category 2 Generator Owners. 2. We point out a misspelling of the work "ride-through" within the first paragraph of the Background Section of the Implementation Plan. 3. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments. The Implementation Plans for Milestone 2 projects are aligned for demonstration of performance. The misspelling has been corrected.	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	

Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the response to EEI, the MRO NSRF.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	
Comment	

- AES CE is concerned by the language in several Measures reading "Each Generator Owner and Transmission Owner have **evidence of actual disturbance monitoring**…". There will be many plants that do not experience an applicable disturbance before this Standard becomes effective and therefore cannot demonstrate adherence to ride-through requirements as prescribed. We are also concerned about expectations for this Measure as time goes on, are we expected to document and record every applicable disturbance and the asset's performance? Setting up monitoring/tracking/retention for this portion of the Measures is a huge additional burden that will be ongoing unless clarification is provided.
- OEMs have not been forthcoming with operating limit data/equipment trip capabilities, and will not comment on or approve alternative proposed settings without a significant amount of studies and simulations from the GO first. Due to the lack of information from OEMs, we are concerned that the exemption process in R4 will be impossible to meet within the 12 month timeframe for larger GOs.
- Quality EMT models including all equipment information needed are not available for legacy equipment (inverters, PPCs). Many legacy inverters do not have an EMT model, and those that do have models are not adequately validated against equipment

performance. Creation of models is either not supported or can be developed at very high cost. Models created after the inverters were initially released are of inadequate quality because the equipment is no longer able to be in a lab environment. • To consider this, AESCE suggests that the SDT include exceptions for legacy equipment where the performance may not be predictable specifically due to a lack of modeling or inverter information.	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the responses to PRC-028-1 regarding data requirements and preservation of disturbance monitoring data as well as PRC-030-1 for analytical triggers. A GO is not required to independently determine when a system disturbance has occurred nor does PRC-029-1 requirements make those determinations. As such demonstration of compliance with PRC-028-1 should be leverage to demonstrate when a grid disturbance occurred. A GO would be required to provide such documentation 12 months following the effective date, which is 12 months following the approval of PRC-029-1; allowing for 24 months to complete the requirement. Model quality will be required as part of Milestone 3 directives. Frequency exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	
Document Name	
Comment	
TAL understands that the committee was following previous precedent of the 20MVA or greater facilities; however, we believe this standard will create undue hardship on utilities who will be required to meet this standard. 20MVA seems like a low threshold for the size of IBRs. TAL believes the impact of IBRs as small as 20 MVA seems minimal to the integrity of the BES.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. This applicability is consistent with the approved changes to registration within NERC's Rules of Procedure as well as directives from FERC Order No. 901.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	

Response
Thank you for your comment.

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	

Comment

Section 4: Applicability:

4.2 is not aligned with the PRC-028. The DT should consider the alignment of the applicability section between all IBR standards.

1) It is not clear to me what “The Elements associated with...” means in 4.2.1. Does it mean power system elements?

R2 The new wording in Section 2.1.3 is unclear.

MRO NSRF recommends it be changed to “Prioritize Real Power or Reactive Power delivery when the voltage is less than 0.95 per unit, the voltage is within the continuous operating region, and the IBR cannot deliver both Real Power and Reactive Power due to a current limit or Reactive Power limit unless otherwise specified through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.”

R3 The MRO NSRF is still concerned with the lack of provisions for exemptions for frequency limitation (RoCof) that may put some of the legacy IBR in a non-compliant state and may require a costly upgrade to meet R3 requirements.

MRO NSRF Recommends the adoption of a frequency ride requirement for legacy equipment be delayed until Generator Owners can properly evaluate the capability of legacy equipment.

R4 The CEA is not a defined NERC term in the Glossary of Terms Used in NERC standard list, MRO NSRF recommends spelling out Compliance Enforcement Authority (CEA) in Requirement R4 subpart 4.2 since it is the first time seeing that term in the requirement language.

Attachment #1 MRO NSRF agrees with removing the previous figures 1 and 2 from attachment # 1 but we recommend adding at least three voltage waveform examples into TR to illustrate how the Table 1 and 2 should be used to determine the compliance with voltage ride through **TR** More information should be added to some frequency waveform examples in TR to illustrate how to calculate the RoCoF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The applicability sections have been aligned. Frequency exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds. CEA has been spelled out. The figures in attachment 1 were removed to prevent confusion with setting curves (like PRC-024).	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	
Document Name	2020-02_Unoffical_Comment_Form_07222024(HQ).docx
Comment	
see attached file	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
R3 refers to “must Ride-through zone” but Attachment 2 does not identify what this zone is.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See Figure 1 of attachment 2.	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Energy Segments 5 and 6.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the response to MRO NSRF.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
MP agrees with MRO's NERC Standards Review Forum's (NSRF) additional comments.	
Likes 0	
Dislikes 0	
Response	

Thank you, please see the response to MRO NSRF.	
Greg Sorenson - Greg Sorenson On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Greg Sorenson	
Answer	
Document Name	
Comment	
RF appreciates the improvements made in this version.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	EEI Near Final Draft Comments _ Project 2020-02 PRC-029 Draft 3 _ Rev 0f __ 8_09_2024.docx
Comment	
See comments submitted by the Edison Eclectic Institute in the attached file.	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the response to EEI.	

Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the response to EEI.	

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI offers the following additional comments on the proposed 3rd draft of PRC-029-1: • EEI does not support the inclusion of the phrase "The Elements associated with" as contained in the Facilities Section (4.2.1). The inclusion of this phrase expands the scope in ways that are unclear creating unnecessary compliance confusion. • Bullet 1 under Requirement R1 is unnecessary and should be deleted, noting that facilities are never obligated to stay connected to a fault. • EEI asks that the DT provide additional clarity to Requirement R4, subpart 4.2.2 noting that there is insufficient clarity regarding what is needed to support a hardware limitation and what the deadline is for the submission of a limitation.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. "The Elements" have been removed. Without the clarification, the requirement could be misinterpreted that an IBR is required to Ride-through if connected to a fault. The deadline for submissions for 4.2.2. has been added. It is appropriate for this requirement to be "objective-based". Language in M4 has been adjusted to clarify.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
LG&E/KU greatly appreciates the SDT's work and is providing feedback with the intent of providing helpful input that will assist in creating a clearer and more consistent standard to meet the FERC directives. We acknowledge the large number of comments provided and thank the drafting team for their work on this standard. A summary of our most substantive feedback is below: 1. Change R1 to apply to voltage and frequency Ride-through (and renumber R1 -> R3, R2 -> R1, and R3 -> R2). 2. Remove footnote 3 or, at minimum, clarify that current blocking is allowed only if not prohibited by the associated functional entities. 3. Ensure M1 addresses all of the exemptions in R1. 4. Replace "Reactive Power limit" with "apparent power limit" in R2 Part 2.1.3, and restore the "according to the requirements …" language. 5. R2 Part 2.3 should clarify that current blocking is acceptable only if not prohibited by the associated functional entities. 6. All mentions of continuous, mandatory, and/or permissive operating regions should include a reference to Attachment 1 (e.g., "specified in Attachment 1") since these terms are no longer defined terms. 7. Move R4 Part 4.2.2 up a level (i.e., 4.2.2 -> 4.3, 4.3 -> 4.4) and include a timeline for the GO to notify the associated functional entities after it has received an acceptance or rejection of its hardware limitation. 8. Modify items 1 and 2 in Attachment 1 to better address hybrid plants.	

9. Remove the second sentence of item 7 in Attachment 1.
10. Add an item in Attachment 1 defining "deviation".
11. Add an item in Attachment 1 permitting IBRs to trip for consecutive voltage deviations subject to the requirements of the associated functional entities.
12. Add an item in Attachment 2, "Table 3 is only applicable when the voltage is within the "must Ride-through zone" as specified in Attachment 1."
13. Modify Table 3 to match IEEE 2800 requirements.
14. Remove Figure 1.
15. In locations where alternative performance requirements are discussed, either add Transmission Owner to the list of entities or replace the list (TP, PC, RC, or TOP) with "the associated functional entities". It is the TO that is responsible for establishing and evaluating interconnection requirements for interconnecting generation Facilities (FAC-001/002).

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

1. R1 is maintained separate for clarity on the exemptions.

2. Current blocking mode is allowable in these circumstances in regard to PRC-029-1 and does not supersede or replace a restriction set by the associated functional entities.

3. R1 exemptions are optional.

4. It is encouraged to use defined terms when appropriate. Previous industry comments also significantly preferred usage of Real Power and Reactive Power.

5. Current blocking mode is allowable in these circumstances in regard to PRC-029-1 and does not supersede or replace a restriction set by the associated functional entities.

6. Language of the requirement states "as specified in attachment 1".

7. A timeline for this step has been added.

8. It is unclear what is asked to be modified within the attachments to add clarity.

9. It is unclear why this sentence should be removed.

10. “deviation” in this context is considered to be understood and does not necessitate a defined term.

11. PRC-029-1 establishes the minimum requirements to ride-through.

12. The expectation for an IBR to Ride-through during a voltage and frequency excursion, is to comply with frequency ride-through requirements.

13. Frequency criteria and exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds.

14. The DT has retained Figure 1.

15. The inclusions of these specifics is to assure no ambiguity regarding who must be notified.

Nick Leathers - Ameren - Ameren Services - 3 - SERC	
Answer	
Document Name	
Comment	
Ameren does not have any additional comments for consideration by the drafting team.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	

Each requirement contains statement *"…shall **ensure** the design and operation is such that …"*. The statement has no quantitative meaning nor direct requirements. Let's take R2.2. or R2.3. for example:

Assuming SDT members own and operate IBRs, please explain WHAT YOU WILL DO to comply with R2.2. and R2.3.

WEC Energy Group requests that the Implementation Guidance document be created and published to help industry better understand this convoluted and unclear standard and how to implement it. Following is an example of a standard being unclear:

R2. "Each Generator Owner shall ensure the design and operation is such that the voltage performance for each IBR adheres to the following during a voltage excursion, unless a documented hardware limitation exists in accordance with Requirement R4."

What is defined as "voltage excursion"? Is it the voltage outside the region identified in Attachment 1, or is it something else?

Further, R2.1. goes on to state: "*While the voltage at the high-side of the main power transformer remains within the continuous operation region as specified in Attachment 1, each IBR shall..".*

If the voltage remains within the "continuous operating region", how is that a "voltage excursion".

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Implementation Guidance may be developed by industry and submitted through CMEP mechanisms. Establishing how to comply with requirements is not within the scope of a standard drafting team. R2.1 applies to only the period of time following a system disturbance. Please see the responses to PRC-028-1 regarding data requirements and preservation of disturbance monitoring data as well as PRC-030-1 for analytical triggers. A GO is not required to independently determine when a system disturbance has occurred and the values at their IBR may not have exceeded Attachment 1 or 2 thresholds in all instances.

Carver Powers - Utility Services, Inc. - 4	
Answer	
Document Name	
Comment	
In our entity's review of this project, we are voting in the affirmative. We understand and appreciate that this project addresses important considerations for reliability and security responsiveness. However, we also recognize that this project in its current form presents compliance and performance risks that remain unresolved. While affirmatively supporting this project to address the immediate regulatory assignments tied to FERC Order 901, NERC and the ERO must continue a constructive dialog with industry beyond this vote to truly optimize the impacts of this project on reliability, sustainability, and affordability. We encourage NERC to permit extending the SDT team and project to offer prospective enhancements or revisions to satisfy these compliance and performance risks.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Frequency exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds.

Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	
Document Name	
Comment	
PNM agrees with the comments made by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the response to EEI.	

Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	2020-02_EPRI Comments on Draft 3 of NERC PRC-029 (IBR ride-through) Reliability Standard.pdf
Comment	

I. Introduction

1. The Electric Power Research Institute (EPRI)[1] respectfully submits these comments (This Response) in response to North American Electric Reliability Corporation (NERC)'s request for formal comment on Project 2020-02 Modifications to PRC-024 (Generator Ride-through), issued on July 22, 2024.

2. EPRI closely collaborates with its members inclusive of electric power utilities, Independent System Operators (ISOs), and Regional Transmission Organizations (RTOs), as well as numerous other stakeholders, domestically and internationally. In its role, EPRI conducts independent research and development relating to the generation, delivery, and use of electricity for public benefit by working to help make electricity more reliable, affordable and environmentally safe. EPRI's comments on this topic are technical in nature based upon EPRI's research, development, and demonstration experience over the last 50 years in planning, analyzing, and developing technologies for electric power.

3. EPRI research and technology transfer deliverables are generally accessible on its website to the public, either for free or for purchase, and occasionally subject to licensing, export control, and other requirements.[2] The publicly available and free-of-charge milestone reports from a U.S. Department of Energy (DOE)- and EPRI member-funded research project, Adaptive Protection and Validated Models to Enable Deployment of High Penetrations of Solar PV ("PV-MOD"), [3] and other research deliverables substantiate many of the comments made in This Response.

4. While not a standards development organization (SDO), EPRI conducts research and demonstration projects in relevant areas as well as facilitates knowledge transfer and collaboration that SDOs may, at times, use to inform technical and regulatory standards development, such as in Institute of Electrical and Electronics Engineers (IEEE), International Electrotechnical Commission (IEC), International Council on Large Electric Systems (CIGRE), and NERC.[4]

5. EPRI's comments in This Response address reliability and NERC's draft PRC-029 Reliability Standards for IBRs ride-through requirements developed under project 2020-02. All comments are aimed at providing independent technical information to respond to the draft published by NERC based on EPRI's research and development results and associated staff expertise and do not necessarily reflect the opinions of those supporting and working with EPRI to conduct collaborative research and development. Where appropriate, EPRI's comments do not only address the specific questions of the NOPR but also related scope that may help to inform a final order. Some of EPRI's comments presented in This Response have also been submitted in response to the previous Federal Energy Regulatory Commission's (FERC) Notice of Proposed Rulemaking (NOPR) to direct North American Electric Reliability Corporation (NERC) to develop Reliability Standards for inverter-based resources (IBRs) that cover data sharing, model validation, planning and operational studies, and performance requirements (RM22-12), issued on November 17, 2022.

6. EPRI also submitted comments on the initial draft of PRC-029 which was issued on March 27, 2024, and on Draft 2 which was issued June 18, 2024. This 3rd set of EPRI comments supports the same direction as the previously submitted comments and offers a technical analysis based on the latest "Draft 3".[5]

II. Conclusion

7. EPRI appreciates the opportunity to provide NERC with its technical recommendations and comments on these important topics related to Reliability Standards for IBRs. EPRI looks forward to working with its members, NERC, and other stakeholders on providing further independent technical information on these important questions.

III. Contact Information

Jens C. Boemer, Technical Executive

Manish Patel, Technical Executive

Anish Gaikwad, Deputy Director

Aidan Tuohy, Director, R&D

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[1] EPRI is a nonprofit corporation organized under the laws of the District of Columbia Nonprofit Corporation Act and recognized as a tax-exempt organization under Section 501(c)(3) of the U.S. Internal Revenue Code of 1996, as amended, and acts in furtherance of its public benefit mission. EPRI was established in 1972 and has principal offices and laboratories located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass. EPRI conducts research and development relating to the generation, delivery, and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety, and the environment. EPRI also provides technology, policy and economic analyses to inform long-range research and development planning, as well as supports research in emerging technologies.

[2] https://www.epri.com (last accessed, August 6, 2024)

[3] PV-MOD Project Website. EPRI. Palo Alto, CA: 2024. [Online] https://www.epri.com/pvmod (last accessed, August 6, 2024)

[4] For transparency, we would like to disclose that EPRI collaborates with other organizations such as IEEE, IEC, CIGRE, and NERC; however, EPRI is not a regulatory- or standard-setting organization. EPRI research is often considered in the development of recommendations, guidelines, and best practices that are not determinative.

[5] https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx

Likes 0	

Dislikes 0	
Response	
Thank you for your comments. Please see previous responses.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you. Pease see the response to NPCC RSC.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
NPCC RSC supports the project.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.

Mike Magruder - Avista - Avista Corporation - 1

Answer	
Document Name	

Comment

We concur with EEI's comments.

Likes 0	
Dislikes 0	

Response

Thank you. Please see the response to EEI.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

Southern Company received the following feedback from one of our OEM providers relating to the Frequency Ride-Through requirements in PRC-029:

“...confirms that **neither** its legacy nor new turbines can meet the proposed frequency ride-through requirements. Wind turbines contain hundreds of electromechanical devices that must be redesigned and tested before any new stringent frequency ride-through zones can be confirmed."

"...is currently designing and evaluating our turbines' capabilities according to **IEEE 2800** standards. Consequently, any new requirements deviating from IEEE 2800 will be unfeasible in the near term."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Frequency criteria and exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	
Document Name	
Comment	
Invenergy thanks the drafting team for the opportunity to provide the above comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rhonda Jones - Invenergy LLC - 5	
Answer	
Document Name	
Comment	

Invenergy thanks the drafting team for the opportunity to provide the above comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
George E Brown - Pattern Operators LP - 5	
Answer	
Document Name	
Comment	

Pattern Energy supports Edison Electric Institute’s and Grid Strategies LLC’s comments.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	
Document Name	

Comment

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,Texas RE,NPCC,SERC,RF, Group Name SRC 2024

Answer	
Document Name	

Comment

In the previous posting, the SRC provided this comment which was not addressed in the current version for comment and ballot:

Attachment 1 lists a minimum ride-through time of 1800 seconds for the continuous operation voltage region between 1.05 pu and 1.1 pu (<= 1.1 and >1.05) in Tables 1 and 2. The SRC requests that, consistent with IEEE 2800, an exception for 500 kV systems be allowed such that the minimum ride-through time for 1.05 pu < voltage <= 1.1 pu for 500 kV systems is "Continuous," because the 1.05 pu < voltage <= 1.1 pu voltage range is within the normal operation range for some systems, such as PJM's system.

The SRC again requests the exception for 500KV systems be incorporated. The SDT has not explainedwhy this difference from the IEEE 2800 is appropriate for 500 KV reliability.

We recommend the M1 references to Sequence Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder be adjusted to lower case terms, as these are not defined in the Glossary of Terms. PRC 28 utilizes acronyms for these that may be appropriate for this standard. Similarly a change was made in R4 to replace Regional Entity with CEA, which is an undefined term and acronym in the Glossary. Suggest spelling this out and considering defining or pointing to the Rules of Procedure.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
IEEE 2800-2022 is not a mandatory nor enforceable standard. NERC cannot adopt the standard per the Rules of Procedure and the DT cannot be required to reference other material. Specific revisions to PRC-029-1 may be pursued in future revisions with technically supporting information documenting the reliability need.
Frequency exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds.
These terms have been lowercased and CEA has been spelled out as noted.

Srinivas Kappagantula - Arevon Energy - 5	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
MISO understands the increased need for Ride-through capabilities as system inertia decreases. We also see challenges for equipment to demonstrate compatibility with the frequency requirements (Attachment 2) which go beyond industry standards (IEEE 2800) and MISO's current Tariff requirements. MISO's plan for conformity currently relies on IEEE P2800.2 and we are planning to use that as the basis for testing to ensure IBRs meet MISO Tariff requirements. We ask that consideration be given to aligning PRC-029 with other existing industry standards.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. Frequency exemptions have been addressed in the latest draft to address significant OEM design capability limits regarding frequency thresholds.	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
Regarding the Implementation Plan. Six months after FERC approval is unreasonable to have equipment and procedures in place and changes made. Especially considering several entities will need to order and install new monitoring equipment from most likely the same companies. This implementation plan should be the same as PRC-28. NCPA understands Ferc Order 901. The SDT has not provided any cost or expected reliability indices improvement estimates. Consequently, it is impossible for entities to determine if this proposal is cost effective to address recommendations of FERC order 901 or if, or to what extent, this proposal will improve reliability. Reliability standards should not be added or changed until the SDT provides said information so that Registered Entities can make educated determinations related to the cost and benefits of reliability standard modifications or new proposals. The SDT has not provide a cost or tangible reliability benefit estimate. Thus we are unable to analyze the cost and reliability benefits this proposal would provide without any data. And, ironically GO/GOP IBR Entities are being asked to spend money to procure and install a bunch of devices to record data and/or to perform new activities that may, or may not, improve reliability. And if they do improve reliability, we don't have any idea if the reliability benefits are worth the cost. Electricity customers' rates would need to be raised and there is no justification or hard evidence related to the improved reliability increase magnitude; i.e. no cost/benefit justification to provide electricity customers as to why their rates are increasing.	
Likes 0	

Dislikes 0	
Response	

Thank you for your comments.
It is unclear what is meant in reference to “six months” or the gap noted, as these are not in the implementation plan. A GO would be required to comply with the design portions of PRC-029-1 12 months after approval, and would align the performance based aspects of those requirements with PRC-028. This was intended to allow entities to align their compliance with both standards.
Please refer to the NERC Rules of Procedure regarding NERC’s development of Reliability Standards to comply with directives from FERC.

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	
Document Name	
Comment	

WECC believes that PRC-029 does a good job being consistent on use of IBR (and PRC-028 and PRC-030 DTs should take note on consistency.) Note that the redlined version of the posted Standard did not capitalize “reactive power” in M2 but the clean version did. Another example is Footnote 11 in the redline version used “active power” but clean version was changed to “Real Power”. DT could receive responses based on either document and needs to ensure consistency in the clean version or note the differences.

WECC suggests that Requirement 4 could be removed and listed as actions to be done within the Implementation Plan. From an auditing perspective, noncompliance is based on administrative issues (failure to provide in 12 months) and is only applicable to units already “in-service” as of the effective date. “In-service” is meant to be exactly what? (WECC has an applicable temr in the NERC Glossary, but that is only appliable in the Western Interconnection. Different entites may have a differend definition of "in-service." Suggest a defintion be developed.) First synch date the IBR is “in-service”. Reliability issues can happen with units not at the COD date and this issue should not be ignored or exacerbated by assuming, if that is the case, that “in-service” equated to COD. There will be discussions as to what the effective date is (for R4 specifically) due to the Implementation Plan dependence provided by the DT. This again calls for a timeline to be provided for each Standard being considered especially for these IBR-related Standards as the IPs are not clearly defined. Still not clear why CEAs need notification of hardware limitations within a Standard. A onetime Alert for R4 may be appropriate followed up by a Periodic Data Submittal

when hardware issues are alleviated (currently no response to CEA is required which begs the question why inform them in the first place?). Severe VSL needs to remove CEA as a result of not being in the section for responses required. VSLs for R3 need to be adjusted to use "IBR" versus "facility". VSLs for R4 indicated a basis of effective date of R4 versus effective date of Standard as the language of the Standard states. This needs corrected as those dates may be different. Another clear reason to provide a timeline diagram of Implementation Plan dates. Attachment 2 Bullet 1 for Voltage- Is the "that include wind" limited to type 3 and type 4 for the hybrid aspect? Attachment 2 Bullet 4 for frequency—Need to replace "facility" with IBR. PRC-029 Implementation Plan Requirement 4 "Non-BES IBRs"- Need to change "or" to "for" in the sentence describing R4's timeline for implementation. Bottom of page 5 capitalize "ride-through". All BES IBRs, including those that have repeatedly failed from a performance perspective, default to the PRC-028 timeline which employs an extended timeframe for phased-in implementation. PRC-029 Implementation Plan- Separating the Requirements compliance obligation timeframe out by design and operation is not realistic and gives the false appearance of being partially applicable prior to Jan 1, 2030. The language of the Requirements, as written, will be contested by entities as the language requires both the "design and operation" for BES IBRs and non-BES IBRs. Effectively a review of the design will be an administrative effort for an item that could be designed today but there is no quality or accuracy language for the design aspects. The proof that design was completed in an effective manner to mitigate the risk can only be determined if an event occurs. R4 has additional implementation time built into the Requirement language which provides a false appearance of being applicable on the effective date of the Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	

The drafting team finds “in-service” to generally understood and does not require a definition. Commercial operation dates will always be on or after the in-service, so the DT retains usage of “in-service”.

The initial documentation submittal in R4 is stated within the requirement to be 12 months after the effective date of PRC-029-1, which is 12 months following the approval date of PRC-029-1.

As an entity will be required to inform and remove hardware limitations beyond the dates of the implementation plan, a required is necessary.

The CEA was included within the standard as the approach to comply with the Order No. 901 directive to only allow for a limited and documented set of exemptions.

IBR is now used in the R3 VSL table and bullet 4 of attachment 2.

The phased-in implementation alignment with PRC-028 is to allow for a single strategy to install disturbance monitoring equipment and not create compliance gaps with demonstrating performance during a system disturbance.

Comments in previous drafts significantly desired to include design capability within PRC-029-1 to assist in determinations of compliance outside of experience. Entities will be required to have accurate models based on performance following the implementation of Milestone 3 directives of FERC Order No. 901.

Jennifer Neville - Western Area Power Administration - 1,6

Answer	
Document Name	

Comment

Section 4: Applicability:

{C}4.2 {C}is not aligned with the PRC-028. The DT should consider the alignment of the applicability section between all IBR standards.

{C}1) It is not clear to me what "The Elements associated with..." means in 4.2.1. Does it mean power system elements?

R2 The new wording in Section 2.1.3 is unclear.

MRO NSRF recommends it be changed to "Prioritize Real Power or Reactive Power delivery when the voltage is less than 0.95 per unit, the voltage is within the continuous operating region, and the IBR cannot deliver both Real Power and Reactive Power due to a current limit or Reactive Power limit unless otherwise specified through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator."

R3 The MRO NSRF is still concerned with the lack of provisions for exemptions for frequency limitation (RoCof) that may put some of the legacy IBR in a non-compliant state and may require a costly upgrade to meet R3 requirements.

MRO NSRF Recommends the adoption of a frequency ride requirement for legacy equipment be delayed until Generator Owners can properly evaluate the capability of legacy equipment.

R4 The CEA is not a defined NERC term in the Glossary of Terms Used in NERC standard list, MRO NSRF recommends spelling out Compliance Enforcement Authority (CEA) in Requirement R4 subpart 4.2 since it is the first time seeing that term in the requirement language.

Attachment #1

MRO NSRF agrees with removing the previous figures 1 and 2 from attachment # 1 but we recommend adding at least three voltage waveform examples into TR to illustrate how the Table 1 and 2 should be used to determine the compliance with voltage ride through **TR** More information should be added to some frequency waveform examples in TR to illustrate how to calculate the RoCoF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. "The Elements" have been removed. Without the clarification, the requirement could be misinterpreted that an IBR is required to Ride-through if connected to a fault. The deadline for submissions for 4.2.2. has been added. It is appropriate for this requirement to be "objective-based". Language in M4 has been adjusted to clarify.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own. In addition, ERCOT encourages NERC to consider defining the averaging window for Rate of Change of Frequency, as leaving the averaging window open ended will result in measurement inconsistencies in protection systems and post-event analysis.	
Likes 0	
Dislikes 0	
Response	

Thank you, please see the response to IRC SRC.

Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

Elevate continues to strongly encourage NERC to reconsider adoption of IEEE 2800-2022. The unwillingness to adopt IEEE 2800-2022 by NERC is leading to entirely duplicative efforts that are not serving any additional value as compared to the work conducted in the IEEE 2800-2022 developments. It does not appear that a holistic approach and strategy is being taken to meet the FERC Order No. 901 directives, which is leading to very low ballot scores, significant rework, and misalignment with industry recommended practices.

The draft NERC PRC-029 is duplicative with IEEE 2800-2022 Clause 7 yet only covers a small fraction of the IBR-specific capability/ performance requirements and necessary equipment limitation details that are outlined in that clause. Therefore, there is no clear reliability benefit versus the cost of implementation PRC-029 as compared with IEEE 2800-2022 and the recommendations set forth in the NERC disturbance reports and guidelines. There are three core items that should be addressed in the draft NERC PRC-029 standard:

- Requirement R4 of the standard be updated to include frequency ride-through criteria exemptions for IBRs in-service by the effective date of the standard that have known hardware limitations.
- The draft PRC-029 standard should align the FRT curve with the IEEE 2800 standard’s FRT curve
- If necessary, the "maximization" concept could be introduced to maximize the capabilities of legacy IBRs to the available software/firmware/setting limits.

Elevate strongly recommends a single NERC standard that adopts IEEE 2800-2022 in a uniform and consistent manner. NERC can also issue a reliability guideline or implementation guidance that supports industry implementation of the standard. Rather than recreate parts of IEEE 2800-2022 inconsistently over multiple different standards, Elevate recommends a singular standard for BPS-connected IBR capability and performance requirements related to IEEE 2800-2022. Additional NERC standards can be developed where needed in situations where they are not covered directly with IEEE 2800-2022 (e.g., NERC PRC-030).

Concerns with Draft PRC-029

If the draft PRC-029 standard is to be pursued as currently structured, Elevate would like to highlight the following concerns:

· **Inconsistencies with PRC-029 and IEEE 2800-2022:** There are numerous inconsistencies in the draft standard language and attachment 1 and 2 when compared to IEEE 2800-2022. These should be considered and reviewed for clarity and completeness in the standard.

- IEEE 2800 recognizes FRT requirement limitations, but the standard does not
- IEEE 2800 recognizes limitations with VSC-HVDC equipment in meeting consecutive votlage deviation ride-through capabilite, the PRC-029 standard does not.
- IEEE 2800 allows for an exception for “self-protection” when negative-sequence voltage is greater than specified duration and threshold, which may be required for Type III WTG based plants. PRC-029 does not have this exception.
- IEEE 2800 recognizes 500kV system voltages are actually operated in the range of 525kV and therefore has equipment rated to 550kV. These 500kV operating conditions and corresponding updated voltage ride-through curves should be considered in the standard.
- In IEEE 2800 the frequency ride-through criteria defines 10-minute time periods for the cumulative specifications of FRT, whereas the standard defines them in a 15 minute time period (Table 3 of Attachment 2). This should be clarified and identified.
- IEEE 2800 has an exception on IBR post-disturbance current limitations for voltage disturbances that reduce RPA voltage to less than 50% of nominal, but the standard does not have this exception.
- A ride-through duration of 1800 seconds is specified in both IEEE 2800 and draft PRC-029 for V > 1.05 and ≤ 1.10. PRC-029 is silent on the cumulative time period for this requirement, whereas IEEE 2800-2022 specifies that this is cumulative over a 3600 second time period.
- Attachment 2: frequency ride-through criteria should be updated to fully match with IEEE 2800. Creating a different FRT ride-through curve without adequate technical justification will continue to challenge the industry.
- The standard should be updated to explicitly state that the voltage ride-through curves are to be interpreted as voltage vs time duration as is stated in IEEE 2800. This is to ensure that there is no incorrect interpretation that these curves are “envelope” curves. This could be done by adding a new note to explicitly call out the voltage vs time duration interpretation of the curves.

Likes 0	
Dislikes 0	

Response

IEEE 2800-2022 is not a mandatory nor enforceable standard. NERC cannot adopt the standard per the Rules of Procedure and the DT cannot be required to reference other material. Specific revisions to PRC-029-1 may be pursued in future revisions with technically supporting information documenting the reliability need.	
Bill Zuretti - Electric Power Supply Association - 5	
Answer	
Document Name	EPSA FINAL Comments on IBR Standards .pdf
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see previous responses.	

Reminder

Standards Announcement

Project 2020-02 Modifications to PRC-024 (Generator Ride-through) | PRC-029-1

Additional Ballots and Non-binding Poll Open through August 12, 2024

Now Available

The additional ballots and non-binding poll for **PRC-029-1 - Frequency and Voltage Ride-through Requirements for Inverter-based Resources** is open through **8 p.m. Eastern, Monday, August 12, 2024.**

This will be the last opportunity for NERC to ballot these projects through traditional mechanisms. The Board may take requisite action during the August 2024 Board of Trustees meeting to ensure directives are met.

The Standards Committee approved waivers to the Standard Processes Manual at their December 2023 meeting. These waivers were sought by NERC Standards staff for reduced formal comment and ballot periods. This will assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 901. *FERC Order 901 was issued under* Docket No. RM22-12-000 *on October 19, 2023.*

To assist industry in this upcoming comment and ballot period, NERC has released a Milestone 2 Summary that provides high-level overview of the current state of the associated projects and their interrelationships. The standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Manager of Standards Development, Jamie Calderon (via email) or at 404-960-0568 Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2020-02 Modifications to PRC-024 (Generator Ride-through) observer list” in the Title and Description Boxes.

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404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2020-02 Modifications to PRC-024 (Generator Ride-through) | PRC-024-4 and PRC-029-1

Formal Comment Period Open through August 12, 2024

Now Available

A formal comment period for **PRC-029-1 - Frequency and Voltage Ride-through Requirements for Inverter-based Resources**, is open through **8 p.m. Eastern, Monday, August 12, 2024.**

This will be the last opportunity for NERC to ballot these projects through traditional mechanisms. The Board may take requisite action during the August 2024 Board of Trustees meeting to ensure directives are met.

The Standards Committee approved waivers to the Standard Processes Manual at their December 2023 meeting. These waivers were sought by NERC Standards staff for reduced formal comment and ballot periods. This will assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 901. *FERC Order 901 was issued under* Docket No. RM22-12-000 *on October 19, 2023.*

To assist industry in this upcoming comment and ballot period, NERC has released a Milestone 2 Summary that provides high-level overview of the current state of the associated projects and their interrelationships. The standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Note: PRC-024-4 passed the recent additional ballot (conducted June 28 – July 8, 2024). The drafting team will be moving this standard to a final ballot when the PRC-029-1 ballots open (August 2-12, 2024) as only non-substantive revision(s) were made.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Additional ballots for the standard and implementation plan, as well as the non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **August 2-12, 2024**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Manager of Standards Development, Jamie Calderon (via email) or at 404-960-0568 Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2020-02 Modifications to PRC-024 (Generator Ride-through) observer list” in the Description Box.

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/342)
Ballot Name: 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-029-1 AB 3 ST
Voting Start Date: 8/2/2024 12:01:00 AM
Voting End Date: 8/12/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 239
Total Ballot Pool: 267
Quorum: 89.51
Quorum Established Date: 8/12/2024 3:33:21 PM
Weighted Segment Value: 52.89

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	74	1	21	0.457	25	0.543	0	20	8
Segment: 2	8	0.8	6	0.6	2	0.2	0	0	0
Segment: 3	54	1	19	0.463	22	0.537	0	7	6
Segment: 4	14	1	7	0.7	3	0.3	0	3	1
Segment: 5	67	1	14	0.318	30	0.682	0	15	8
Segment: 6	45	1	10	0.294	24	0.706	0	6	5
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	5	0.5	5	0.5	0	0	0	0	0
Totals:	267	6.3	82	3.332	106	2.968	0	51	28

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner	Carly Miller	Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Third-Party Comments
1	Duke Energy	Katherine Street	Ellese Murphy	Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Negative	Comments Submitted
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Abstain	N/A
1	Exelon	Daniel Gacek		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu	Jay Sethi	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Abstain	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	Comments Submitted
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		None	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Negative	Comments Submitted
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
3	Exelon	Kinte Whitehead		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Abstain	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	Comments Submitted
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Negative	Third-Party Comments
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
4	Austin Energy	Tony Hua		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Third-Party Comments
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Georgia System Operations Corporation	Katrina Lyons		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Abstain	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	American Municipal Power	Amy Ritts		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
5	Decatur Energy Center LLC	Megan Melham		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
5	Invenergy LLC	Rhonda Jones		Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Manitoba Hydro	Kristy-Lee Young		None	N/A
5	Muscatine Power and Water	Chance Back		Abstain	N/A
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		None	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Comments Submitted
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
6	AEP	Mathew Miller		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Third-Party Comments
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
6	Invenergy LLC	Colin Chilcoat		Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Luminant - Luminant Energy	Russell Ferrell		Negative	Third-Party Comments
6	Manitoba Hydro	Brandin Stoesz		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		None	N/A
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Abstain	N/A
6	Portland General Electric Co.	Stefanie Burke		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Comments Submitted
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party Comments
10	Northeast Power Coordinating Council	Gerry Dunbar		Affirmative	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 267 of 267 entries

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/342)
Ballot Name: 2020-02 Modifications to PRC-024 (Generator Ride-through) Implementation Plan AB 3 OT
Voting Start Date: 8/2/2024 12:01:00 AM
Voting End Date: 8/12/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 242
Total Ballot Pool: 271
Quorum: 89.3
Quorum Established Date: 8/12/2024 3:33:38 PM
Weighted Segment Value: 60.04

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	75	1	23	0.5	23	0.5	0	21	8
Segment: 2	8	0.7	7	0.7	0	0	0	1	0
Segment: 3	55	1	21	0.512	20	0.488	0	8	6
Segment: 4	14	1	8	0.8	2	0.2	0	3	1
Segment: 5	68	1	18	0.419	25	0.581	0	16	9
Segment: 6	46	1	13	0.371	22	0.629	0	6	5
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	5	0.3	3	0.3	0	0	0	2	0
Totals:	271	6	93	3.602	92	2.398	0	57	29

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner	Carly Miller	Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Third-Party Comments
1	Duke Energy	Katherine Street	Ellese Murphy	Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Negative	Comments Submitted
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Abstain	N/A
1	Exelon	Daniel Gacek		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Glencoe Light and Power Commission	Terry Volkmann		Abstain	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu	Jay Sethi	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Abstain	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	Comments Submitted
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		None	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Negative	Comments Submitted
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
3	Exelon	Kinte Whitehead		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Abstain	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	Comments Submitted
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Negative	Third-Party Comments
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
4	Austin Energy	Tony Hua		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Third-Party Comments
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Abstain	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	American Municipal Power	Amy Ritts		Abstain	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
5	Decatur Energy Center LLC	Megan Melham		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
5	Invenergy LLC	Rhonda Jones		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Manitoba Hydro	Kristy-Lee Young		None	N/A
5	Muscatine Power and Water	Chance Back		Abstain	N/A
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		None	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Comments Submitted
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
6	AEP	Mathew Miller		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Third-Party Comments
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Great River Energy	Brian Meloy		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Luminant - Luminant Energy	Russell Ferrell		Negative	Third-Party Comments
6	Manitoba Hydro	Brandin Stoesz		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		None	N/A
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Abstain	N/A
6	Portland General Electric Co.	Stefanie Burke		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Comments Submitted
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Public Utility District No. 1 of Chelan County	Robert Witham		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party Comments
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Showing 1 to 271 of 271 entries

BALLOT RESULTS

Ballot Name: 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-029-1 | Non-binding Poll AB 3 NB
Voting Start Date: 8/2/2024 12:01:00 AM
Voting End Date: 8/12/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 221
Total Ballot Pool: 251
Quorum: 88.05
Quorum Established Date: 8/12/2024 3:33:47 PM
Weighted Segment Value: 42.58

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	71	1	18	0.462	21	0.538	24	8
Segment: 2	7	0.4	3	0.3	1	0.1	3	0
Segment: 3	51	1	15	0.429	20	0.571	11	5
Segment: 4	14	1	7	0.7	3	0.3	3	1
Segment: 5	62	1	13	0.361	23	0.639	17	9
Segment: 6	41	1	7	0.259	20	0.741	7	7
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0
Segment: 9	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	5	0.4	3	0.3	1	0.1	1	0
Totals:	251	5.8	66	2.81	89	2.99	66	30

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner	Carly Miller	Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Comments Submitted
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Comments Submitted
1	Duke Energy	Katherine Street	Ellese Murphy	Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Negative	Comments Submitted
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Abstain	N/A
1	Exelon	Daniel Gacek		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Abstain	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		Abstain	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	Comments Submitted
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		None	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Negative	Comments Submitted
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
3	Exelon	Kinte Whitehead		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
4	Austin Energy	Tony Hua		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Georgia System Operations Corporation	Katrina Lyons		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Abstain	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
5	Decatur Energy Center LLC	Megan Melham		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Muscatine Power and Water	Chance Back		Abstain	N/A
5	National Grid USA	Robin Berry		Negative	Comments Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		None	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
6	AEP	Mathew Miller		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Luminant - Luminant Energy	Russell Ferrell		Negative	Comments Submitted
6	Muscatine Power and Water	Nicholas Burns		None	N/A
6	New York Power Authority	Shelly Dineen		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Abstain	N/A
6	Portland General Electric Co.	Stefanie Burke		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted

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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

Draft 4 of PRC-029-1 is posted for a formal comment and additional ballot.

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023
25-day formal comment period and initial ballot	March 27 – April 22, 2024
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15-day formal comment period and additional ballot	July 22 – August 12, 2024

Anticipated Actions	Date
14-day formal comment period and additional ballot	September 17 – September 30, 2024
Final Ballot	None Required
Board adoption	October 8, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Ride-through: The plant/facility remains connected and continues to operate through voltage or frequency system disturbances.

A. Introduction

1. **Title:** **Frequency and Voltage Ride-through Requirements for Inverter-based Resources**

2. **Number:** **PRC-029-1**

3. **Purpose:** To ensure that IBRs Ride-through to support the Bulk Power System (BPS) during and after defined frequency and voltage excursions.

4. **Applicability:**

    4.1 Functional Entities:

    4.1.1. Generator Owner

    4.2 Facilities:

    4.2.1. Bulk Electric System (BES) IBRs

    4.2.2. Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Effective Date: See Implementation Plan for Project 2020-02 – PRC-029-1

Standard-only Definition: None

B. Requirements and Measures

R1. Each Generator Owner shall ensure the design and operation is such that each IBR meets or exceeds Ride-through requirements, in accordance with the "must Ride-through[1] zone" as specified in Attachment 1, except in the following conditions: *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

- The IBR needed to electrically disconnect in order to clear a fault;
- The voltage at the high-side of the main power transformer[2] went outside an accepted hardware limitation, in accordance with Requirement R4;
- The instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer and is initiated by a non-fault switching event on the transmission system[3]; or
- The Volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

M1. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to Ride-through requirements, as specified in Requirement R1. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) to demonstrate that the operation of each IBR did adhere to Ride-through requirements, as specified in Requirement R1. If the Generator Owner choose to utilize Ride-through exemptions that occur within the "must Ride-through zone" and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) data to demonstrate that the IBR failed to Ride-through during a phase jump of greater than or equal to 25 electrical degrees, and documentation from their Transmission Planner, Reliability Coordinator, Planning Coordinator, or Transmission Operator that a non-fault initiated switching event occurred.

R2. Each Generator Owner shall ensure the design and operation is such that the voltage performance for each IBR adheres to the following during a voltage excursion, unless a documented hardware limitation exists in accordance with Requirement R4. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

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[1] Includes no tripping associated with phase lock loop loss of synchronism.

[2] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for IBRs. In case of IBR connecting via a dedicated Voltage Source Converter High Voltage Direct Current (VSC-HVDC), the main power transformer is the main power transformer on the receiving end.

[3] Current blocking mode may be used for non-fault initiated phase jumps greater than 25 degrees in order to prevent tripping.

2.1. While the voltage at the high-side of the main power transformer remains within the continuous operation region as specified in Attachment 1, each IBR shall:

2.1.1 Continue to deliver the pre-disturbance level of Real Power or available Real Power[4], whichever is less.[5]

2.1.2 Continue to deliver Reactive Rower up to its Reactive Power limit and according to its controller settings.

2.1.3 Prioritize Real Power or Reactive Power when the voltage is less than 0.95 per unit, the voltage is within the continuous operating region, and the IBR cannot deliver both Real Power and Reactive Power due to a current limit or Reactive Power limit, unless otherwise specified through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.2. While voltage at the high-side of the main power transformer is within the mandatory operation region as specified in Attachment 1, each IBR shall exchange current, up to the maximum capability to provide voltage support, on the affected phases during both symmetrical and asymmetrical voltage disturbances, either under[6]:

- Reactive Power priority by default; or
- Real Power priority if required through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.3. While voltage at the high-side of the main power transformer is within the permissive operation region, as specified in Attachment 1, each IBR may operate in current blocking mode if necessary to avoid tripping. Otherwise, each IBR shall follow the requirements for the mandatory operation region in Requirement R2.2.

2.3.1 If an IBR enters current blocking mode, it shall restart current exchange in less than or equal to five cycles of positive sequence voltage returning to a continuous operation region or mandatory operation region.

2.4. Each IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable high voltage thresholds and time

[4] "Available Real Power" refers to changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes of facility Real Power attributed to IBR tripping in whole or part.

[5] Except if this would occur during a frequency excursion. The Real Power response should recover in accordance with the primary frequency controller.

[6] In either case and if required, the magnitude of Real Power and reactive current shall be as specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

durations in its response as voltage recovers from the mandatory or permissive operation regions to the continuous operation region.

2.5. Each IBR shall restore Real Power output to the pre-disturbance or available level[7] (whichever is lesser) within 1.0 second when the voltage at the high-side of the main power transformer returns from the mandatory operation region or permissive operation region (including operating in current blocking mode) to the continuous operation region, as specified in Attachment 1, unless an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires a lower post-disturbance Real Power level requirement or requires a different post-disturbance Real Power restoration time through other mechanisms.[8]

M2. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to requirements, as specified in Requirement R2. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) data to demonstrate that the operation of each IBR did adhere to performance requirements, as specified in Requirement R2, during each voltage excursion measured at the high-side of the main power transformer. Regarding R2.1.3, R2.2, and R2.5, the Generator Owner shall retain evidence of receiving such performance requirements, (e.g., email exchange, contract information) if the Transmission Planner, Transmission Operator, Reliability Coordinator, or Planning Coordinator has required the Generator Owner through other mechanisms to follow performance requirements other than those in Requirement R2 (e.g., ramp rates, Reactive Power prioritization).

R3. Each Generator Owner shall ensure the design and operation is such that each IBR meets or exceeds Ride-through requirements during a frequency excursion event whereby the System frequency remains within the "must Ride-through zone" according to Attachment 2 and the absolute rate of change of frequency (RoCoF)[9] magnitude is less than or equal to 5 Hz/second, unless a documented hardware limitation exists in accordance with Requirement R4. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

M3. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to Ride-through requirements, as specified in Requirement R3. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) data to demonstrate the

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[7] "Available Real Power" refers to changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes of facility Real Power attributed to IBR tripping in whole or part.

[8] Except if this would occur during a frequency excursion. The Real Power response should recover in accordance with the primary frequency controller.

[9] Rate of change of frequency (RoCoF) is calculated as the average rate of change for multiple calculated system frequencies for a time period of greater than or equal to 0.1 second. RoCoF is not calculated during the fault occurrence and clearance.

operation of each IBR did adhere to Ride-through requirements, as specified in Requirement R3, during each frequency excursion event measured at the high-side of the main power transformer.

R4. Each Generator Owner identifying an IBR that is in-service by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1-R3, and requires an exemption from specific Ride-through criteria shall:[10] *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1. This documentation shall include:

4.1.1 Identifying information of the IBR (name and facility number);

4.1.2 Which aspects of Ride-through requirements that the IBR would be unable to meet and the capability of the hardware due to the limitation;

4.1.3 Identification of the specific piece(s) of hardware causing the limitation;

4.1.4 Technical documentation verifying the limitation is due to hardware that would need to be physically replaced to meet all Ride-through criteria, and that the limitation cannot be remedied by software updates or setting changes; and

4.1.5 Information regarding any plans to remedy the hardware limitation (such as an estimated date).

4.2. Provide a copy of the information detailed in Requirement R4.1, except for any material considered by the original equipment manufacture to be proprietary information, to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the Compliance Enforcement Authority (CEA) no later than 12 months following the effective date of PRC-029-1.[11]

4.2.1 Provide any response for additional information requested by the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA to the requestor within 90 days of the request.

4.2.2 Provide a copy of the acceptance of a hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of receiving the acceptance.[12]

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[10] The exemption requests for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
[11] To the extent the original equipment manufacturer considers any material to be proprietary, the Generator Owner is required to share this proprietary material only with the CEA.
[12] Acceptance by the CEA is verification that the information provided includes all information listed in Requirement R4.1.

4.3. Each Generator Owner with a previously accepted limitation that replaces the hardware causing the limitation shall document and communicate such a hardware change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the hardware change.

4.3.1 When existing hardware causing the limitation is replaced, the exemption for that Ride-through criteria no longer applies.

M4. Each Generator Owner submitting for an exemption for an IBR that is in-service by the effective date of PRC-029-1, shall have evidence of submission to the CEA consistent with the information listed in Requirement R4.1. Each Generator Owner shall have evidence of communicated copies of each submission in accordance with Requirement R4.2 and to the associated entities described in Requirement R4.2. Acceptable types of evidence for submittals include, but are not limited to, meeting minutes, agreements, copies of procedures or protocols in effect, or email correspondence. Acceptable types of evidence for a hardware limitation may include, but is not limited to damage curves provided by the original equipment manufacturer. Each Generator Owner that receives a request for additional information under Requirement R4.2.1 shall have evidence of providing that information within 90 days. Each Generator Owner that replaces hardware at an IBR that is directly associated with an accepted exemption and that hardware is the cause for the limitation, shall have evidence of communicating the hardware change to the associated entities described in Requirement R4.3 within 90 days of the hardware replacement.

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.

   1.2. **Evidence Retention:** 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.

   - Each Generator Owner shall retain evidence with Requirements R1, R2, and R3 in this standard for 36 calendar months or the date of the last audit, whichever is greater.
   - Each Generator Owner shall retain evidence with Requirement R4 in this standard for five calendar years or the date of the last audit, whichever is greater.

   1.3. **Compliance Monitoring and Enforcement 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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The Generator Owner failed to ensure the design capability of each applicable IBR to Ride-through in accordance with Attachment 1, except for those conditions identified in Requirement R1.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to Ride-through requirements in accordance with Attachment 1, except for those conditions identified in Requirement R1.
R2.	The Generator Owner failed to ensure the design capability of each applicable IBR to adhere to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.
R3.	The Generator Owner failed to ensure the design capability of each applicable IBR to Ride-through in accordance with Attachment 2, unless a documented hardware limitation exists in accordance with Requirement R4.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to Ride-through requirements in accordance with Attachment 2, unless a documented hardware limitation exists in accordance with Requirement R4.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 12 months, but less than or equal to 15 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 90 days but less than or equal to 120 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 90 days but less than or equal to 120 days after receiving the acceptance of a hardware limitation by the CEA. OR	The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 15 months, but less than or equal to 18 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 120 days, but less than or equal to 150 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 120 days but less than or equal to 150 days after receiving the acceptance of a hardware limitation by the CEA.	The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 18 months, but less than or equal to 24 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 150 days but less than or equal to 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 150 days but less than or equal to 180 days after receiving the acceptance of a hardware limitation by the CEA. OR	The Generator Owner failed to document complete information for IBR identified with known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1, R2, or R3. OR The Generator Owner failed to provide a copy to the applicable entities as detailed in Requirement R4.2 within 24 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and CEA more than 90 calendar days but less than or equal to 120 calendar days after the change to the hardware.	OR The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 120 calendar days but less than or equal to 150 calendar days after the change to the hardware.	The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 150 calendar days but less than or equal to 180 calendar days after the change to the hardware.	entities as detailed in Requirement R4.2.2 more than 180 days after receiving the acceptance of a hardware limitation by the CEA. The Generator Owner with a previously communicated hardware limitation that replace the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s),Reliability Coordinator(s), and CEA more than 180 days after the change to the hardware.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan .

Version History

Version	Date	Action	Change Tracking
Initial Draft	3/27/24	Draft	
Draft 2	6/4/24	Revised following initial comment review	
Draft 3	7/22/24	Revised following additional comment review	
Draft 4	9/12/24	Revised following additional comment review	

Attachment 1: Voltage Ride-Through Criteria

Table 1: Voltage Ride-through Requirements for AC-Connected Wind IBR [13]

Voltage (per unit)[14]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[15]	N/A
≥ 1.10	Mandatory Operation Region	1.0
> 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90	Mandatory Operation Region	3.00
< 0.70	Mandatory Operation Region	2.50
< 0.50	Mandatory Operation Region	1.20
< 0.25	Mandatory Operation Region	0.16
< 0.10	Permissive Operation Region	0.16

Table 2: Voltage Ride-through Requirements for All Other IBR

Voltage (per unit)[16]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[17]	N/A
> 1.10	Mandatory Operation Region	1.0
> 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90	Mandatory Operation Region	6.00
< 0.70	Mandatory Operation Region	3.00
< 0.50	Mandatory Operation Region	1.20
< 0.25	Mandatory Operation Region	0.32
< 0.10	Permissive Operation Region	0.32

[13] Type 3 and type 4 wind resources directly connected to the AC Transmission System.
[14] Refer to bullet #4 below.
[15] These conditions are referred to as the “may Ride-through zone”.
[16] Refer to bullet #4 below.
[17] These conditions are referred to as the “may Ride-through zone”.

1. Table 1 applies to type 3 and type 4 wind IBR or hybrid IBR that include wind, unless connected via a dedicated Voltage Source Converter - High Voltage Direct Current (VSC-HVDC) transmission facility.
2. Table 2 applies to all other IBR types not covered in Table 1; including, but not limited to, the following facilities:
   a. IBR, regardless of their energy resource, interconnecting via a dedicated VSC-HVDC transmission facility.
   b. Other IBR or hybrid IBR consisting of photovoltaic (PV) and BESS.
3. The applicable voltage for VSC-HVDC system with a dedicated connection to an IBR is on the AC side of the transformer(s) that is (are) used to connect the VSC-HVDC system to the interconnected transmission system.
4. The voltage base for per unit calculation is the nominal phase-to-ground or phase-to-phase transmission system voltage unless otherwise defined by the Planning Coordinator, Transmission Planner, or Transmission Owner.
5. The applicable voltage for Tables 1 and 2 is identified as the voltage max/min of phase-to-neutral or phase-to-phase fundamental root mean square (RMS) voltage at the high-side of the main power transformer.
6. Tables 1 and 2 are only applicable when the frequency is within the “must Ride-through zone” as specified in Figure 1 of Attachment 2.
7. At any given voltage value, each IBR shall Ride-through unless the time duration at that voltage has exceeded the specified minimum Ride-through time duration. If the voltage is continuously varying over time, it is necessary to add the duration within each band of Tables 1 and 2 over any 10 second time period.
8. The specified duration of the mandatory operation regions and the permissive operation regions in Tables 1 and 2 is cumulative over one or more disturbances within any 10 second time period.
9. The IBR may trip for more than four deviations of the applicable voltage at the high-side of the main power transformer outside of the continuous operation region within any 10 second time period.
10. Instantaneous trip settings based on instantaneously calculated voltage measurements with less than filtering lengths of one cycle (16.6 millisecond) are not permissible.
11. The “must Ride-through zone” is the combined area of the mandatory operating regions, the continuous operating regions, and the permissive operating region. All area outside of these operating regions is referred to as the “may Ride-through zone”.

Attachment 2: Frequency Ride-Through Criteria

Table 3: Frequency Ride-through Capability Requirements

System Frequency (Hz)	Minimum Ride-Through Time (sec)
> 61.8	May trip
> 61.2	299
≤ 61.2 and ≥ 58.8	Continuous
< 58.8	299
< 57.0	May trip

1. Frequency measurements are taken at the high-side of the main power transformer.
2. Frequency is measured over a period of time (typically 3-6 cycles) to calculate system frequency at the high-side of the main power transformer.
3. Instantaneous or single points of measurement may not be used in the determination of control settings.
4. At any given frequency value, each IBR shall Ride-through unless the time duration at that frequency has exceeded the specified minimum ride-through time duration.
5. The specified durations of Table 3 are cumulative over one or more disturbances within a 10-minute time period.

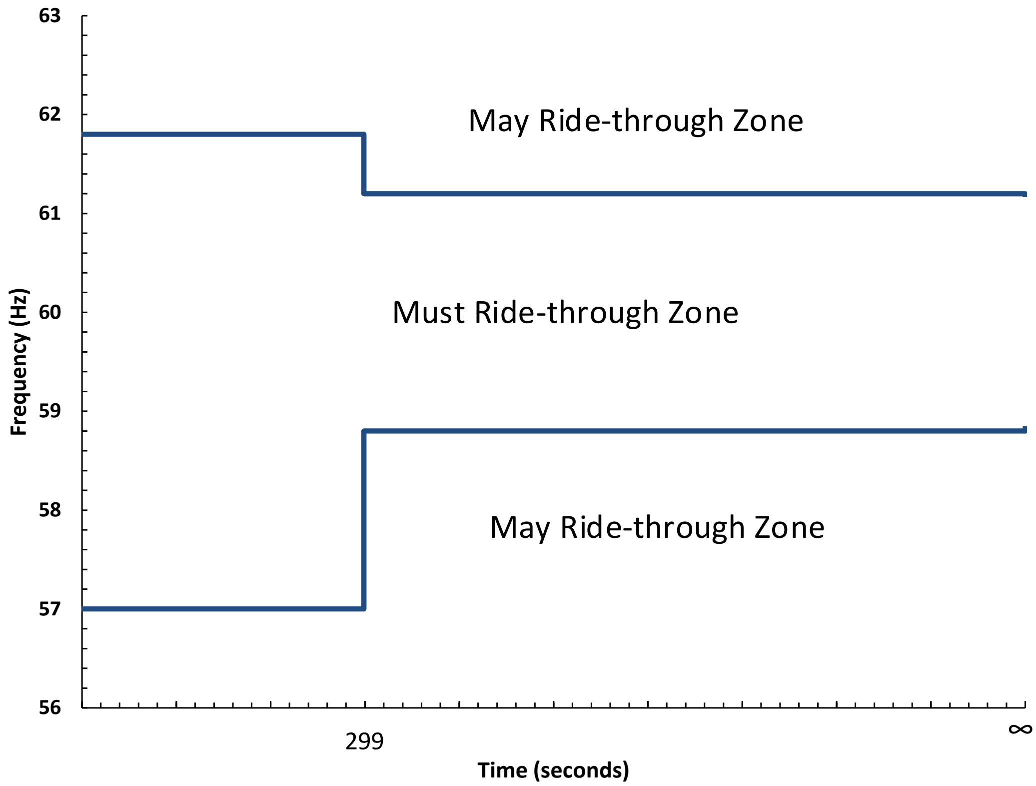

Figure 1: PRC-029 Frequency Ride-through Requirements

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

Draft 4 of PRC-029-1 is posted for a formal comment and additional ballot.

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Final Ballot	None Required
Board adoption	October 8, 2024

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This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Ride-through: The ~~entire~~ plant/facility remains~~ing~~ connected ~~to the Bulk Power System~~ and continues~~ing in its entirety~~ to operate through voltage and frequency ~~S~~system ~~D~~disturbances.

~~The term Inverter-based Resource (IBR) refers to proposed definitions being developed under the Project 2020-06 Verifications of Models and Data for Generators. As of this posting, the proposed definition of an IBR is:~~

~~**IBR:** A plant/facility consisting of individual devices that are capable of exporting Real Power through a power electronic interface(s) such as inverter or converter, and that are operated together as a single resource at a common point of interconnection to the electric system. IBRs include, but are not limited to, plants/facilities with solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell devices.~~

A. Introduction

1. **Title:** **Frequency and Voltage Ride-through Requirements for Inverter-based Resources**
2. **Number:** **PRC-029-1**
3. **Purpose:** To ensure that IBRs Ride-through to support the Bulk Power System (BPS) during and after defined frequency and voltage excursions.
4. **Applicability:**

   4.1 Functional Entities:

   4.1.1. Generator Owner

   4.2 Facilities:

   4.2.1. ~~The Elements associated with (1)~~ Bulk Electric System (BES) IBR~~s; and (2)~~

   ~~4.2.1.~~**4.2.2.** Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Effective Date: See Implementation Plan for Project 2020-02 – PRC-029-1

Standard-only Definition: None

B. Requirements and Measures

R1. Each Generator Owner shall ensure the design and operation is such that each IBR meets or exceeds Ride-through requirements, in accordance with the "must Ride-through[1] zone" as specified in Attachment 1, except ~~for~~in the following conditions: *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

- The IBR needed to electrically disconnect in order to clear a fault;~~ or~~
- The voltage at the high-side of the main power transformer[2] went outside an accepted hardware limitation, in accordance with Requirement R4;~~ or~~
- The instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer and is initiated by a non-fault switching event on the transmission system[3]; or
- The Volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

M1. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to Ride-through requirements, as specified in Requirement R1. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall retain evidence of actual disturbance monitoring (i.e. ~~S~~sequence of ~~E~~event ~~R~~recorder, ~~D~~dynamic ~~D~~disturbance ~~R~~recorder, and ~~F~~fault ~~R~~recorder) to demonstrate that the operation of each IBR did adhere to Ride-through requirements, as specified in Requirement R1. If the Generator Owner choose to utilize Ride-through exemptions that occur within the "must Ride-through zone" and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e. ~~S~~sequence of ~~E~~event ~~R~~recorder, ~~D~~dynamic ~~D~~disturbance ~~R~~recorder, and ~~F~~fault ~~R~~recorder) data to demonstrate that the IBR failed to Ride-through during a phase jump of greater than or equal to 25 electrical degrees, and documentation from their Transmission Planner, Reliability Coordinator, Planning Coordinator, or Transmission Operator that a non-fault initiated switching event occurred.

R2. Each Generator Owner shall ensure the design and operation is such that the voltage performance for each IBR adheres to the following during a voltage excursion, unless a documented hardware limitation exists in accordance with Requirement R4. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

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[1] Includes no tripping associated with phase lock loop loss of synchronism.

[2] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for IBRs. In case of IBR connecting via a dedicated Voltage Source Converter High Voltage Direct Current (VSC-HVDC), the main power transformer is the main power transformer on the receiving end.

[3] Current blocking mode may be used for non-fault initiated phase jumps greater than 25 degrees in order to prevent tripping.

2.1. While the voltage at the high-side of the main power transformer remains within the continuous operation region as specified in Attachment 1, each IBR shall:

2.1.1 Continue to deliver the pre-disturbance level of Real Power or available Real Power[4], whichever is less.[5]

2.1.2 Continue to deliver Reactive Rower up to its Reactive Power limit and according to its controller settings.

2.1.3 Prioritize Real Power or Reactive Power when the voltage is less than 0.95 per unit, the voltage is within the continuous operating region, and the IBR cannot deliver both Real Power and Reactive Power due to a current limit or Reactive Power limit, unless otherwise specified through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.2. While voltage at the high-side of the main power transformer is within the mandatory operation region as specified in Attachment 1, each IBR shall exchange current, up to the maximum capability to provide voltage support, on the affected phases during both symmetrical and asymmetrical voltage disturbances, either under[6]:

- Reactive Power priority by default; or
- Real Power priority if required through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.3. While voltage at the high-side of the main power transformer is within the permissive operation region, as specified in Attachment 1, each IBR may operate in current blocking mode if necessary to avoid tripping. Otherwise, each IBR shall follow the requirements for the mandatory operation region in Requirement R2.2.

2.3.1 If an IBR enters current blocking mode, it shall restart current exchange in less than or equal to five cycles of positive sequence voltage returning to a continuous operation region or mandatory operation region.

2.4. Each IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable high voltage thresholds and time

[4] "Available Real Power" refers to changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes of facility Real Power attributed to IBR tripping in whole or part.
[5] Except if this would occur during a frequency excursion. The Real Power response should recover in accordance with the primary frequency controller.
[6] In either case and if required, the magnitude of Real Power and reactive current shall be as specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

durations in its response as voltage recovers from the mandatory or permissive operation regions to the continuous operation region.

2.5. Each IBR shall restore Real Power output to the pre-disturbance or available level[7] (whichever is lesser) within 1.0 second when the voltage at the high-side of the main power transformer returns from the mandatory operation region or permissive operation region (including operating in current blocking mode) to the continuous operation region, as specified in Attachment 1, unless an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires a lower post-disturbance Real Power level requirement or requires a different post-disturbance Real Power restoration time through other mechanisms.[8]

M2. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to requirements, as specified in Requirement R2. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e. ~~S~~sequence of ~~E~~event ~~R~~recorder, ~~D~~dynamic ~~D~~disturbance ~~R~~recorder, and ~~F~~fault ~~R~~recorder) data to demonstrate that the operation of each IBR did adhere to performance requirements, as specified in Requirement R2, during each voltage excursion measured at the high-side of the main power transformer. In regard to R2.1.3, R2.2, and R2.5, the Generator Owner shall retain evidence of receiving such performance requirements, (e.g. email exchange, contract information) if the Transmission Planner, Transmission Operator, Reliability Coordinator, or Planning Coordinator has required the Generator Owner through other mechanisms to follow performance requirements other than those in Requirement R2 (e.g. ramp rates, Reactive Power prioritization).

R3. Each Generator Owner shall ensure the design and operation is such that each IBR meets or exceeds Ride-through requirements during a frequency excursion event whereby the System frequency remains within the “must Ride-through zone” according to Attachment 2 and the absolute rate of change of frequency (RoCoF)[9] magnitude is less than or equal to 5 Hz/second, unless a documented hardware limitation exists in accordance with Requirement R4. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

M3. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to Ride-through requirements, as specified in Requirement R3. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e. ~~S~~sequence of ~~E~~event ~~R~~recorder, ~~D~~dynamic ~~D~~disturbance ~~R~~recorder, and ~~F~~fault ~~R~~recorder) data to

[7] “Available Real Power" refers to changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes of facility Real Power attributed to IBR tripping in whole or part.

[8] Except if this would occur during a frequency excursion. The Real Power response should recover in accordance with the primary frequency controller.

[9] Rate of change of frequency (RoCoF) is calculated as the average rate of change for multiple calculated system frequencies for a time period of greater than or equal to 0.1 second. RoCoF is not calculated during the fault occurrence and clearance.

demonstrate the operation of each IBR did adhere to Ride-through requirements, as specified in Requirement R3, during each frequency excursion event measured at the high-side of the main power transformer.

R4. Each Generator Owner identifying an IBR that is in-service by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting ~~voltage~~ Ride-through criteria as detailed in Requirements R1~~ and ~~-R3~~2~~, and requires an exemption from specific ~~voltage~~ Ride-through criteria shall:[10] *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1. This documentation shall include:

4.1.1 Identifying information of the IBR (name and facility number~~#~~);

4.1.2 Which aspects of ~~voltage~~ Ride-through requirements that the IBR would be unable to meet and the capability of the hardware due to the limitation;

4.1.3 Identify the specific piece(s) of hardware causing the limitation;

4.1.4 ~~Supporting t~~Technical documentation verifying the limitation is due to hardware that would need~~s~~ to be physically replaced to meet all Ride-through criteria, and~~ or~~ that the limitation cannot be removed by software updates or setting changes, and;

4.1.5 Information regarding any plans to remedy the hardware limitation (such as an estimated date).

4.2. Provide a copy of the information detailed in Requirement R4.1, except for any material considered by the original equipment manufacture to be proprietary information, to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the Compliance Enforcement Authority (CEA) no later than 12 months following the effective date of PRC-029-1.[11]

4.2.1 Provide ~~A~~any response ~~t~~for additional information requested by the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA shall be provided back to the requestor within 90 days of the request.

4.2.2 Provide a copy of the acceptance of an hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission

[10] The exemption requests for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

[11] To the extent the original equipment manufacturer considers any material to be proprietary, the Generator Owner is required to share this proprietary material only with the CEA.

Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of receiving the acceptance.[12]

4.3. Each Generator Owner with a previously accepted limitation that replaces the hardware causing the limitation shall document and communicate such a hardware change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the hardware change.

4.3.1 When existing hardware causing the limitation is replaced, the exemption for that Ride-through criteria no longer applies.

M4. Each Generator Owner submitting for an exemption for an IBR that is in-service by the effective date of PRC-029-1, shall have evidence of submission to the CEA consistent with the information listed in Requirement R4.1. Each Generator Owner shall have evidence of communicated copies of each submission in accordance with Requirement R4.2 and to the associated entities described in Requirement R4.2. Acceptable types of evidence for submittals include but are not limited to, meeting minutes, agreements, copies of procedures or protocols in effect, or email correspondence. Acceptable types of evidence for a hardware limitation may include, but is not limited to damage curves~~documentation that contains study results, experience from an actual event, or~~ provided by the original equipment manufacturer~~'s advice~~. Each Generator Owner that receives a request for additional information under Requirement R4.2.1 shall have evidence of providing that information within 90 ~~calendar~~ days. Each Generator Owner that replaces hardware at an IBR that is directly associated with an accepted exemption and that hardware is the cause for the limitation, shall have evidence of communicating the hardware change to the associated entities described in Requirement R4.3 within 90 ~~calendar~~ days of the hardware replacement.

[12] Acceptance by the CEA is verification that the information provided includes all information listed in Requirement R4.1.

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.

   1.2. **Evidence Retention:** 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.

   - Each Generator Owner shall retain evidence with Requirements R1, R2, and R3 in this standard for 36 calendar months or the date of the last audit, whichever is greater.
   - Each Generator Owner shall retain evidence with Requirement R4 in this standard for five calendar years or the date of the last audit, whichever is greater.

   1.3. **Compliance Monitoring and Enforcement 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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Owner failed to ~~demonstrate~~ ensure the design capability of each applicable IBR to Ride-through in accordance with Attachment 1, except for those conditions identified in Requirement R1.	N/A	N/A	The Generator Owner failed to ensure ~~demonstrate~~ each applicable IBR adhered to Ride-through requirements in accordance with Attachment 1, except for those conditions identified in Requirement R1.
R2.	The Generator Owner failed to ensure ~~demonstrate~~ the design capability of each applicable IBR to adhere to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.	N/A	N/A	The Generator Owner failed to ensure ~~demonstrate~~ each applicable IBR adhered to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.
R3.	The Generator Owner failed to ensure ~~demonstrate~~ the design capability of each applicable IBR to Ride-through in accordance with Attachment 2, unless a documented hardware	N/A	N/A	The Generator Owner failed to ensure ~~demonstrate~~ each applicable IBR adhered to Ride-through requirements in accordance with Attachment 2, unless a documented hardware limitation exists in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	limitation exists in accordance with Requirement R4.			accordance with Requirement R4.
R4.	The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 12 months, but less than or equal to 15 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 90 days but less than or equal to 120 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 90 days but less than or equal to 120 days after receiving the	The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 15 months, but less than or equal to 18 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 120 days, but less than or equal to 150 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 120 days but less than or equal to 150 days after receiving the	The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 18 months, but less than or equal to 24 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 150 days but less than or equal to 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 150 days but less than or equal to 180 days after receiving the	The Generator Owner failed to document complete information for IBR identified with known hardware limitations that prevent the IBR from meeting voltage Ride-through criteria as detailed in Requirements R1, ~~or~~ R2, or R3. OR The Generator Owner failed to provide a copy to the applicable entities as detailed in Requirement R4.2 within 24 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	acceptance of a hardware limitation by the CEA. OR The Generator Owner with a previously communicated hardware limitation that replace the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and CEA more than 90 ~~calendar~~ days but less than or equal to 120 ~~calendar~~ days after the change to the hardware. ~~OR~~ ~~The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 12 months but less than or equal to 15 months after the effective date of Requirement R4.~~ ~~OR~~	acceptance of a hardware limitation by the CEA. OR The Generator Owner with a previously communicated hardware limitation that replace the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 120 ~~calendar~~ days but less than or equal to 150 ~~calendar~~ days after the change to the hardware. ~~OR~~ ~~The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 120 days but less than or equal to 150 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.~~	acceptance of a hardware limitation by the CEA. OR The Generator Owner with a previously communicated hardware limitation that replace the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 150 ~~calendar~~ days but less than or equal to 180 ~~calendar~~ days after the change to the hardware. ~~OR~~ ~~The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 150 days but less than or equal to 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.~~	OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 180 days after receiving the acceptance of a hardware limitation by the CEA. OR The Generator Owner with a previously communicated hardware limitation that replace the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s),Reliability Coordinator(s), and CEA more than 180 ~~calendar~~ days after the change to the hardware. ~~OR~~ ~~The Generator Owner failed to provide a copy to the applicable entities as detailed in Requirement R4.2 within 24~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 90 days but less than or equal to 120 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.~~			~~months after the effective date of Requirement R4.~~ ~~OR~~ ~~The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.~~

D. Regional Variances

None.

E. Associated Documents

Implementation Plan .

Version History

Version	Date	Action	Change Tracking
Initial Draft	3/27/24	Draft	
Draft 2	6/4/24	Revised following initial comment review	
Draft 3	7/22/24	Revised following additional comment review	
Draft 4	9/12/24	Revised following additional comment review	

Attachment 1: Voltage Ride-Through Criteria

Table 1: Voltage Ride-through Requirements for AC-Connected Wind IBR [13]

Voltage (per unit)[14]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[15]	N/A
≥ 1.10	Mandatory Operation Region	1.0
> 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90	Mandatory Operation Region	3.00
< 0.70	Mandatory Operation Region	2.50
< 0.50	Mandatory Operation Region	1.20
< 0.25	Mandatory Operation Region	0.16
< 0.10	Permissive Operation Region	0.16

Table 2: Voltage Ride-through Requirements for All Other IBR

Voltage (per unit)[16]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[17]	N/A
> 1.10	Mandatory Operation Region	1.0
> 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90	Mandatory Operation Region	6.00
< 0.70	Mandatory Operation Region	3.00
< 0.50	Mandatory Operation Region	1.20
< 0.25	Mandatory Operation Region	0.32
< 0.10	Permissive Operation Region	0.32

[13] Type 3 and type 4 wind resources directly connected to the AC Transmission System.
[14] Refer to bullet #4 below.
[15] These conditions are referred to as the “may Ride-through zone”.
[16] Refer to bullet #4 below.
[17] These conditions are referred to as the “may Ride-through zone”.

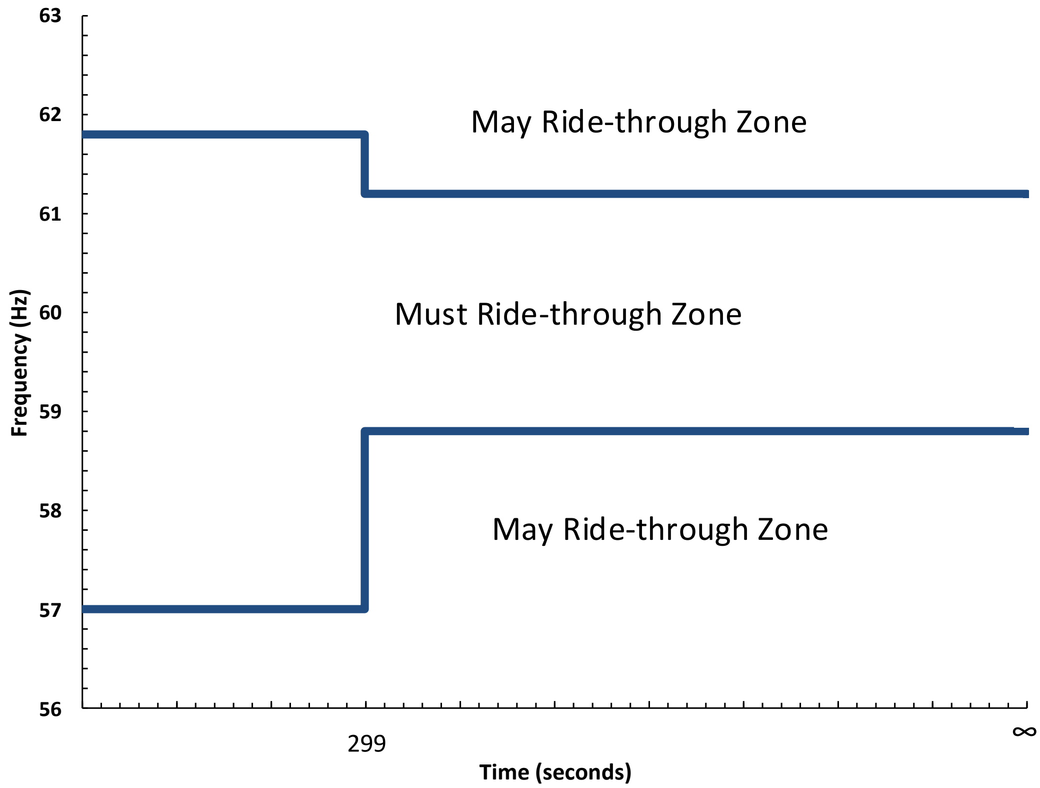
1. Table 1 applies to type 3 and type 4 wind IBR or hybrid IBR that include wind, unless connected via a dedicated Voltage Source Converter - High Voltage Direct Current (VSC-HVDC) transmission facility.
2. Table 2 applies to all other IBR types not covered in Table 1; including, but not limited to, the following facilities:
   a. IBR, regardless of their energy resource, interconnecting via a dedicated VSC-HVDC transmission facility.
   b. Other IBR or hybrid IBR consisting of photovoltaic (PV) and BESS.
3. The applicable voltage for VSC-HVDC system with a dedicated connection to an IBR is on the AC side of the transformer(s) that is (are) used to connect the VSC-HVDC system to the interconnected transmission system.
4. The voltage base for per unit calculation is the nominal phase-to-ground or phase-to-phase transmission system voltage unless otherwise defined by the Planning Coordinator, Transmission Planner, or Transmission Owner.
5. The applicable voltage for Tables 1 and 2 is identified as the voltage max/min of phase-to-neutral or phase-to-phase fundamental root mean square (RMS) voltage at the high-side of the main power transformer.
6. Tables 1 and 2 are only applicable when the frequency is within the “must Ride-through zone” as specified in Figure 1 of Attachment 2.
7. At any given voltage value, each IBR shall Ride-through unless the time duration at that voltage has exceeded the specified minimum Ride-through time duration. If the voltage is continuously varying over time, it is necessary to add the duration within each band of Tables 1 and 2 over any 10 second time period.
8. The specified duration of the mandatory operation regions and the permissive operation regions in Tables 1 and 2 is cumulative over one or more disturbances within any 10 second time period.
9. The IBR may trip for more than four deviations of the applicable voltage at the high-side of the main power transformer outside of the continuous operation region within any 10 second time period.
10. Instantaneous trip settings based on instantaneously calculated voltage measurements with less than filtering lengths of one cycle (16.6 millisecond) are not permissible.
11. The “must Ride-through zone” is the combined area of the mandatory operating regions, the continuous operating regions, and the permissive operating region. All area outside of these operating regions is referred to as the “may Ride-through zone”.

Attachment 2: Frequency Ride-Through Criteria

Table 3: Frequency Ride-through Capability Requirements

System Frequency (Hz)	Minimum Ride-Through Time (sec)
> 61.8	May trip
> 61.2	299
≤ 61.2 and ≥ 58.8	Continuous
< 58.8	299
< 57.0	May trip
~~System Frequency (Hz)~~	~~Minimum Ride-Through Time (sec)~~
~~> 64.0~~	~~May trip~~
~~≥ 61.8~~	~~6~~
~~≥ 61.5~~	~~299~~
~~> 61.2~~	~~660~~
~~≤ 61.2 and > 58.8~~	~~Continuous~~
~~≤ 58.8~~	~~660~~
~~≤ 58.5~~	~~299~~
~~≤ 57.0~~	~~6~~
~~< 56.0~~	~~May trip~~

1. Frequency measurements are taken at the high-side of the main power transformer.
2. Frequency is measured over a period of time (typically 3-6 cycles) to calculate system frequency at the high-side of the main power transformer.
3. Instantaneous or single points of measurement may not be used in the determination of control settings.
4. At any given frequency value, each IBR shall Ride-through unless the time duration at that frequency has exceeded the specified minimum ride-through time duration.
5. The specified durations of Table 3 are cumulative over one or more disturbances within a 10~~5~~-minute time period.


63
62
61
60
59
58
57
56
Frequency (Hz)
May Ride-through Zone
Must Ride-through Zone
May Ride-through Zone
299
∞
Time (seconds)

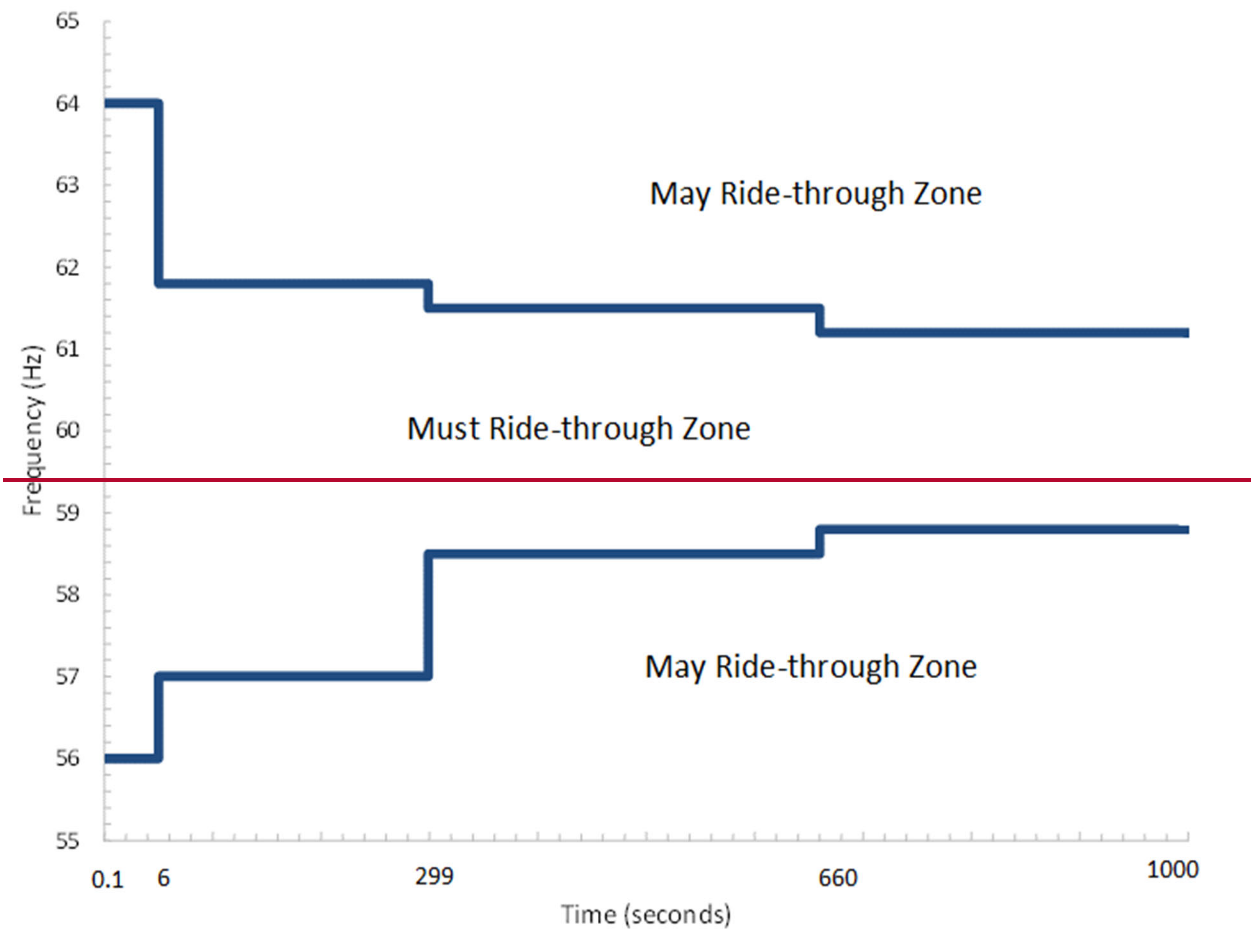


Figure 1: PRC-029 Frequency Ride-through Requirements

Implementation Plan

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
Reliability Standards PRC-024-4 and PRC-029-1

Applicable Standard(s)

- PRC-024-4 – Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and Type 2 Wind Resources, and Synchronous Condensers
- PRC-029-1 – Frequency and Voltage Ride-through Requirements for Inverter-based Generating Resources

Requested Retirement(s)

- PRC-024-3 Frequency and Voltage Protection Settings for Generating Resources

Prerequisite Standard(s)

- None

Proposed Definition(s)

- None

Applicable Entities

- See subject Reliability Standards.

Background

The purpose of Project 2020-02 is to modify Reliability Standard PRC-024-3 or replace it with a performance-based Ride-through standard that ensures generators remain connected to the Bulk Power System (BPS) during system disturbances. Specifically, the project focuses on using disturbance monitoring data to substantiate inverter-based resource (IBR) ride-through performance during grid disturbances. The project also ensures associated generators that fail to Ride-through system events are addressed with a corrective action plan (if possible) and reported to necessary entities for situational awareness.

The purpose for this project is based on the culmination of multiple analyses conducted by the ERO Enterprise regarding widespread IBR tripping events. Furthermore, the NERC Inverter-Based Resource Performance Subcommittee[1] has developed comprehensive recommendations for improved

[1] See documents at the NERC IRPS website: https://www.nerc.com/comm/RSTC/Pages/IRPS.aspx and the previous Inverter-Based Resource Performance Working Group website https://www.nerc.com/comm/RSTC/Pages/IRPWG.aspx

performance of IBRs, including the recommendation to develop comprehensive ride-through requirements.

In October 2023, FERC issued Order No. 901[2] which directs the development of new or modified Reliability Standards that include new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. In January 2024, NERC submitted a filing to FERC outlining a comprehensive work plan to address the directives within Order No. 901.[3] Within the work plan, NERC identified three active Standards Development projects that would need to be filed for regulatory approval with FERC by November 4, 2024. These projects include **2020-02 Modifications to PRC-024 (Generator Ride-through)**[4], **2021-04 Modifications to PRC-002-2**[5], and **2023-02 Analysis and Mitigation of BES Inverter-based Resource Performance Issues**[6].

Project 2020-02

Proposed Reliability Standard PRC-029-1 is a new Reliability Standard that includes Ride-through requirements and performance requirements for IBRs. The scope of this project was adjusted to align with associated regulatory directives from FERC Order No. 901 and the scope of the other projects related to “Milestone 2” of the NERC work plan. The components of this project’s Standard Authorization Request (SAR) that related to the inclusions of new data recording requirements are covered in Project 2021-04 and the proposed new PRC-028-1 Reliability Standard. Components of this project’s SAR that relate to analytics and corrective actions plans are covered in Project 2023-02 and the proposed new PRC-030-1 Reliability Standard.

PRC-029-1 includes requirements for Generator Owner IBR to continue to inject current and perform voltage support during a BPS disturbance. The standard also specifically requires Generator Owner IBR to prohibit momentary cessation in the no-trip zone during disturbances.

PRC-024-4 includes modifications to revise applicable facility types to remove IBR, retain type 1 and type 2 wind, and to include synchronous condensers.

[2] See FERC Order 901, Docket No. RM22-12-000; https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false; October 19, 2023

[3] See INFORMATIONAL FILING OF THE NORTH AMERICAN RELIABILITY CORPORATION REGARDING THE DEVELOPMENT OF RELIABILITY STANDARDS RESPONSIVE TO ORDER NO. 901 https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/NERC%20Compliance%20Filing%20Order%20No%20901%20Work%20Plan_packaged%20-%20public%20label.pdf; January 17, 2024

[4] See NERC Standards Development Project page for Project 2002-02; https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx

[5] See NERC Standards Development Project page for Project 2021-04; https://www.nerc.com/pa/Stand/Pages/Project-2021-04-Modifications-to-PRC-002-2.aspx

[6] See NERC Standards Development Project page for Project 2023-02; https://www.nerc.com/pa/Stand/Pages/Project-2023-02-Performance-of-IBRs.aspx

General Considerations

This implementation plan recognizes the urgent need for Reliability Standards to address IBR ride through performance, as demonstrated by multiple event reports of the last decade, while providing a reasonable period of time for entities to develop the necessary procedures and change their protection and control settings to meet the new requirements. The ERO Enterprise acknowledges that there are IBRs currently in operation and unable to meet voltage Ride-through requirements due to their inability to modify their coordinated protection and control settings. Consistent with FERC Order No. 901, a limited and documented exemption process for those IBR is appropriate and included within this Implementation Plan. Other NERC Standards Development projects will be pursued to address ongoing identification and mitigation of any potential reliability impacts to the BPS for such exemptions.

This implementation plan also recognizes that certain requirements (Requirements R1, R2, and R3) call for entities to “ensure the design and operation” of their IBR units meets certain criteria. Design elements may be implemented more expeditiously than operation requirements; the latter of which will require entities to show compliance through use of actual disturbance monitoring data. Therefore, this implementation plan provides staggered timeframes by which entities shall first ensure the design of their IBR units meets the criteria (12 months following regulatory approval). Subsequent compliance with the “operation” elements of these requirements shall become due as entities install disturbance monitoring equipment on each applicable IBR in accordance with the implementation plan for proposed Reliability Standard PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-based Resources.

The ERO Enterprise acknowledges that Generator Owners and Generator Operators owning or operating Bulk Power System connected IBRs that do not meet NERC’s current definition of Bulk Electric System (“BES”) will be registered no later than May 2026 in accordance with the IBR Registration proceeding in FERC Docket No. RR24-2. To ensure an orderly registration and compliance process for these entities, as well as fairness and consistency in the standard’s application among similar asset types, this implementation plan provides additional time for both new and existing registered entities to come into compliance with Reliability Standard PRC-029-1’s requirements for their applicable IBRs not meeting the BES definition. In so doing, this implementation plan advances an orderly process for new registrants while allowing existing entities to focus their immediate efforts on their assets posing the highest risk to the reliable operation of the Bulk Power System.

Effective Date and Phased-in Compliance Dates

The effective dates for the proposed Reliability Standards are provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance dates for those particular sections represent the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

PRC-024-4

Where approval by an applicable governmental authority is required, Reliability Standard PRC-024-4 shall become effective on the first day of the first calendar quarter that is twelve months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the Reliability Standard PRC-024-4 shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

PRC-029-1

Where approval by an applicable governmental authority is required, Reliability Standard PRC-029-1 shall become effective on the first day of the first calendar quarter that is twelve months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the Reliability Standard PRC-029-1 shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

PRC-029-1 Phased-in Compliance Dates

Requirements R1, R2, and R3

Capability-Based Elements

Bulk Electric System IBRs

Entities shall comply with the portion of Requirements R1, R2, and R3 relating to the **design** of their BES IBRs to meet the requirements by the effective date of the standard.

Applicable Non-BES IBRs[7]

Entities shall not be required to comply with Requirements R1, R2, and R3 relating to the **design** of their applicable non-BES IBRs until the later of: (1) January 1, 2027; or (2) the effective date of the standard.

Performance-Based Elements (all applicable IBRs)

Entities shall not be required to comply with the portion of Requirements R1, R2, and R3 relating to the **operation** of IBRs to meet the requirements until the entity has established the required

[7] The standard defines such as IBRs as "Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV."

disturbance monitoring equipment capabilities for those IBRs in accordance with the implementation plan for Reliability Standard PRC-028-1.

Requirement R4

Bulk Electric System IBRs
Entities shall comply with Requirement R4 for their BES IBRs by the effective date of the standard.

Applicable Non-BES IBRs
Entities shall not be required to comply with Requirement R4 or their non-BES IBRs until the later of: (1) January 1, 2027; or (2) the effective date of the standard.

Retirement Date

PRC-024-3

Reliability Standard PRC-024-3 shall be retired immediately prior to the effective date of Reliability Standards PRC-024-4 and PRC-029-1 in the particular jurisdiction in which the revised standard is becoming effective.

Equipment Limitations and Process for Requirement R4

Consistent with FERC Order No. 901, a limited and documented exemption for some legacy IBR with certain documented equipment limitations are acceptable. Per the Order, these IBRs are

> "…typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements."[8]

To ensure compliance with Requirement R4 and alignment with FERC Order No. 901, only those IBR that are in operation as of the effective date of PRC-029-1 may be considered for potential exemption. Further, only those IBR that are unable to meet voltage ride-through requirements due to their inability to modify their coordinated protection and control settings may be considered for potential exemption.

[8] Order No. 901 at p. 193.

To: NERC Board of Trustees and Stakeholders

From: NERC Staff and Representatives from the Standards Committee

Re: Summary of Issues and Alternatives Considered, Proposed Reliability Standard PRC-029-1 (Frequency and Voltage Ride-through Requirements for Inverter-based Resources)

Date: September 24, 2024

In Order No. 901, the Federal Energy Regulatory Commission ("FERC") directed the development of new or revised Reliability Standards to address certain reliability issues related to inverter-based resources ("IBRs"), including IBR ride-through performance.[1] To address the IBR ride-through directives, Project 2020-02 Modifications to PRC-024-4 initiated development of proposed Reliability Standard PRC-029-1 (Frequency and Voltage Ride-through Requirements for Inverter-based Resources). However, proposed Reliability Standard PRC-029-1 has failed to pass ballot through the usual standard development process.

Section 321 of the NERC Rules of Procedure allows the NERC Board of Trustees to take special actions when a ballot pool has failed to approve a proposed Reliability Standard that contains a provision to adequately address a specific matter identified in a directive issued by an Applicable Governmental Authority. The NERC Board of Trustees took such action for the proposed PRC-029-1 standard at its August 2024 meeting.[2]

Consistent with Section 321.2 of the NERC Rules of Procedure, the Standards Committee and NERC staff convened a technical conference from September 4-5, 2024 to discuss the issues surrounding the FERC Order No. 901 directives, including whether or not the proposed Reliability Standard PRC-029-1 is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified. This memorandum discusses the issues, an analysis of alternatives considered, and other appropriate matters.

Background

On October 19, 2023, the Commission issued Order No. 901 directing the development of new or revised Reliability Standards to address reliability issues associated with the growth of IBRs on the Bulk-Power

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1 *Reliability Standards to Address Inverter-Based Resources*, Order No. 901, 185 FERC ¶ 61,042, Docket No. RM22-12-000 (Oct. 19, 2023) [hereinafter Order No. 901]. Available here.

2 NERC Board of Trustees, Minutes of the August 15, 2024, available here.

System.[3] The Commission directed NERC to develop new or revised Reliability Standards addressing IBR reliability issues as follows:

1) IBR disturbance monitoring data sharing and post-event performance validation[4] and ride-through performance requirements[5] by November 4, 2024;
2) IBR data and model validation[6] by November 4, 2025; and
3) planning and operational studies[7] for IBRs by November 4, 2026.

The Commission also directed NERC to develop and submit a work plan to develop new and revised Reliability Standards to address these issues in accordance with the specified timeframe.[8]

On January 17, 2024, NERC submitted its Order No. 901 Work Plan,[9] which consists of key milestones to meet the Commission's directives by the filing deadlines mentioned above. **Milestone 2**, in progress, focuses on the development of Reliability Standards to address disturbance monitoring, performance-based ride-through requirements and post-event performance validation for registered IBRs by November 4, 2024.

The Reliability Standards being proposed to address **Milestone 2** of FERC Order 901 are being developed through the following projects:

- Project 2020-02 Modifications to PRC-024 (Generator Ride-through),
- Project 2021-04 Modifications to PRC-002,
- Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues

As of this writing, Projects 2021-04 and 2023-02 are on track for timely completion through the usual NERC standard development process. Project 2020-02, addressing generator ride-through directives from Order No. 901, is the subject of special Board action under Section 321.

Specifically, proposed Reliability Standard PRC-029-1 (Frequency and Voltage Ride-through Requirements for Inverter-based Resources) is a draft standard designed to establish capability-based and performance-based ride-through requirements for IBRs during grid disturbances, to address the Commission directives from Order No. 901. The draft standard failed to achieve consensus from the Registered Ballot Body over

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3 *See Order No. 901, supra,* at PP 229.

4 *See id.* at PP 66-109 (discussing directives related to data sharing requirements).

5 *See id.* at PP 178-211 (discussing directives related to performance requirements).

6 *See id.* at PP 110-161 (discussing directives related to data and model validation requirements).

7 *See id.* at PP 162-177 (discussing directives related to planning and operational studies requirements).

8 *See id.* at P 222.

9 Informational Filing of the North American Electric Reliability Corporation Regarding the Development of Reliability Standards Responsive to Order No. 901, (Docket No. RM22-12-000) (2024) [hereinafter Order No. 901 Work Plan].

multiple ballots, the latest of which occurred between August 2, 2024 to August 12, 2024. This called into question whether development would be completed by FERC's filing deadline of November 4, 2024.

As a result, the NERC Board of Trustees initiated the use of Section 321 at its August 15, 2024 meeting. Under this special authority, the Board directed the Standards Committee to work with NERC Staff to convene a technical conference to gather input from industry to address the outstanding issues and revise PRC-029-1. This memorandum describes the issues that led to the technical conference convening and the alternative solutions that were considered. The proposed PRC-029-1 standard has been revised using input from the technical conference and is submitted for stakeholder ballot. This process must be completed within 45 days of being initiated, which is September 30, 2024. If the re-balloted proposed Reliability Standard achieves at least an affirmative 60% majority vote of the weighted Segment votes cast, then the Board may consider it for adoption under Section 321.

Order No. 901 Directives for Ride-through

In Order No. 901, the Commission cites to multiple event reports as the reason that IBRs should have Reliability Standards for ride-through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults.[10] Below you will find the Commission's specific directives on how IBRs should ride-through disturbances and how exceptions should be applied to certain IBRs. Finding consensus around these directives were a part of the main issues addressed during the technical conference.

> "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults. The new or modified Reliability Standards must require registered IBRs to continue to inject current and perform frequency support during a Bulk-Power System disturbance. Any new or modified Reliability Standard must also require registered IBR generator owners and operators to prohibit momentary cessation in the no-trip zone during disturbances. NERC must submit new or modified Reliability Standards that establish IBR performance requirements, including requirements addressing frequency and voltage ride through, post-disturbance ramp rates, phase lock loop synchronization, and other known causes of IBR tripping or momentary cessation."[11]

> "Therefore, we direct NERC through its standard development process to determine whether the new or modified Reliability Standards should provide for a limited and documented exemption for certain registered IBRs from voltage ride-through performance requirements. Any such exemption should be only for voltage ride-through performance for those existing IBRs that are unable to

[10] See Order No. 901 at PP 190.

[11] See *id.*

modify their coordinated protection and control settings to meet the requirements without physical modification of the IBRs' equipment."[12]

Summary of Issues and Alternatives Considered

The technical conference took place on September 4-5, 2024, and focused on unresolved issues raised by stakeholders raised during the PRC-029-1 comment periods. Specifically, the technical conference focused on: (1) the proposed definition of "Ride-through"; (2) the proposed criteria for frequency ride-through performance; and (3) the feasibility of allowing hardware-based exemptions from the frequency ride-through requirements, similar to the voltage ride-through exemption FERC directed NERC to consider in Order No. 901.[13] These issues, and the alternatives considered, are discussed below.

Ride-Through Definition

The most recent Standard Authorization Request for Project 2020-02 included direction to the drafting team to define the term "ride-through" as necessary. During the development of **Milestone 2** projects, a definition for "ride-through" was considered by the drafting teams of both PRC-029 and PRC-030 as both Reliability Standards leverage the term to refer to acceptable performance criteria outlined in PRC-029. Per the Standards Process Manual (NERC Rules of Procedure Appendix 3A), definitions themselves may not include statements of performance requirements. As such, the specific performance requirements and measures to demonstrate ride-through are to be found within the Requirements and Attachments of PRC-029-1. References to "Ride-through criteria" in PRC-030-1, allow for those additional analytics to include further evaluations with PRC-029-1 Ride-through performance requirements as appropriate while preventing duplication of those performance requirements in different Reliability Standards.

Comments from Draft 3 of PRC-029-1 concerning the proposed definition of "Ride-through" were reviewed. In the previously proposed definition, many stakeholders argued that the proposed definition was too broad and ambiguous, particularly with the inclusion of phrases like "entire" and "in its entirety." Those stakeholders recommended revisions to clarify the definition and ensure it aligns better with IEEE Std 2800™, IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems.[14] The Draft 3 proposed definition of "Ride-through" was discussed at the technical conference and presented on by a member of the original drafting team.[15] The Draft 3 definition was presented as follows: "The entire plant/facility remaining connected to the Bulk Power System and continuing in its entirety to operate through System Disturbances."

As part of the presentation, ten (10) alternative definitions were presented as proposed by commenters during the previous rounds of ballot and formal comment. After the presentation, four (4) of the most

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12 See Order No 901 at PP 193.

13 See Order No 901 at PP 199.

14 Hereinafter referred to as "IEEE 2800-2022".

15 See "Outlining Objectives of a Ride-through Definition" of posted [Standards Committee and NERC Ride-through Technical Conference material]; page 94/129.

distinct definitions were opened to technical conference attendees as a straw poll to gauge overall industry preference. When asked "Which of the following proposed definitions for Ride-through do you think is most correct?":

- 68% voted in favor of the "Ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified.";
- 16% voted in favor of "The plant/facility remaining connected to the Bulk Power System and continuing to operate through System Disturbances as defined in applicable reliability standards.";
- 12% voted in favor of "The entire plant/facility remaining connected to the Bulk Power System and continuing in its entirety to operate through System Disturbances."; and
- 4% voted in favor of "The plant/facility shall remain connected and in service, maintaining the pre-disturbance equipment configuration in operation, throughout the entirety of the system disturbance and recovery."

Following the technical conference, NERC staff, Standards Committee representatives, some members of the drafting team, and FERC staff met to discuss the results of the straw poll as well as previously reviewed material. Based on that discussion, language in the preferred definition such as "ability to withstand", "defined limits" and "as specified" were unclear and were inherently challenging for use in a definition that must be leveraged by multiple Reliability Standards. It was determined that the final draft would proceed with the 2nd most preferred definition, with slight modifications to remove usage of other defined terms that had an embedded usage of the Bulk Electric System defined term. The final definition as proposed in Draft 4 of PRC-029-1 is as follows: "The plant/facility remains connected and continues to operate through voltage or frequency system disturbances."

Proposed Criteria for Frequency Ride-Through Performance

As described in the Project 2020-02 Standard Authorization Request and assigned directives from Order No. 901, the drafting team was tasked with developing new or modified Reliability Standards to assure a performance-based approach to generator ride-through. This scope included requirements that generating resources shall ride-through grid disturbances and include quantitative measures on expectations for ride-through that address all possible causes of tripping and power reductions from generating resources (particularly generator, turbine, inverter, and all plant-level protection and controls).

The proposed new Reliability Standard PRC-029-1 requires generator owners of IBR to both design and operate their IBR plants to ride-through voltage and frequency system disturbances. Requirement R3 and Attachment 2 of PRC-029-1 define the quantitative frequency ride-through criteria by use of measured frequency magnitude and time duration of sustaining that magnitude for all conditions. As discussed during the development of PRC-029-1, many stakeholders commented in previous ballots a preference to leverage those quantitative values as currently established in IEEE 2800-2022.

Frequency ride-through criteria was a prominent discussion of the technical conference. Members of the drafting team presented on the decisions made during the development of these criteria during the technical conference.[16] The presentation explained that the voltage and frequency ride-through zones

[16] See "Review of Voltage and Frequency Ride-through Criteria in PRC-029-1" of posted Standards Committee and NERC Ride-through Technical Conference material; page 47/129.

proposed in Draft 3 of the standard were based on the IEEE 2800-2022 no-trip zones and were established in view of drafting team member experience with frequency excursions in planning and operations. The drafting team also stated the proposed frequency criteria were reasonable and were practical limits of IBR frequency tolerances, inclusive of adequate margins for worst-case conditions.

Following the presentation by the drafting team, NERC staff presented on voltage and frequency Ride-through evaluations taken from recent NERC disturbance reports and the report results from the March 2023 Level 2 Alert.[17] The NERC presentation stressed balancing Bulk Power System needs with reasonable criteria that account for technical capabilities of currently designed equipment. NERC also highlighted a continued need to coordinate messaging during the design and interconnection phases of new IBR to have protection and controller equipment set in accordance with the hardware capability of the IBR rather than only in relation to minimum values established in NERC Reliability Standards.

Two panels regarding frequency criteria were held during the technical conference. The first panel included representatives of various IBR original equipment manufacturers, and the second panel included other members of industry.[18] Discussions from both panels highlighted the following key issues:[19]

- Many IBR designed before 2014 would be unable to meet frequency Ride-through magnitude and duration criteria proposed in Attachment 2 of Draft 3. It was estimated by one panelist that approximately 20 GW of installed capacity would not be able to meet the criteria, indicating significant challenges for legacy IBR without substantial hardware replacement and redesign.
- Many IBR had not been designed to meet a rate of change of frequency (RoCoF) of 5 Hz per second. Of concern from the panelist was the technical basis for determining the need for a 5 Hz RoCoF did not include a study or more thorough evaluation of potential system strength benefits and that different parts of the Bulk Power System have not been demonstrated to require it.
- Recent event reports presented by NERC were all related to voltage excursions, potentially indicating that frequency-based disturbances were less likely to occur. Some panelists contended that this potential lower likelihood of experiencing a frequency event did not align with the expansion of frequency criteria beyond those currently established in IEEE 2800-2022.

After the panels of this topic, two straw polls were opened for attendees of the Ride-through technical conference to provide their feedback for consideration regarding "legacy" IBR and future IBR.

When attendees were asked "Based on the conversation you heard today from our panels, for legacy assets, what should PRC-029 voltage and frequency criteria follow that assures reliability and is reasonable for industry?":

- 64% voted in favor of "Maintain PRC-024 criteria for IBR";

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17 See "Review of Voltage and Frequency Ride-through" of posted Standards Committee and NERC Ride-through Technical Conference material; page 67/129.

18 See "Panel Discussion: Original Equipment Manufacturer Perspectives on Voltage and Frequency Ride-through Criteria" of posted Standards Committee and NERC Ride-through Technical Conference material; pages 85/129 and 86/129.

19 See Day 1 Recording and Transcript of the Standards Committee & NERC Ride-through Technical Conference; Project 2020-02 Modifications to PRC-024 (Generator Ride-through) Related Files; posted September 18, 2024.

- 29% voted in favor of “Adopt voltage and frequency bands proposed in IEEE 2800-2022”; and
- 6% voted in favor of “Retain currently proposed PRC-029 criteria”.

When attendees were asked “Based on the conversation you heard today from our panels, for assets being brought online in the future, what should PRC-029 voltage & frequency criteria follow that assures reliability and is reasonable for industry?”:

- 90% voted in favor of “Adopt voltage and frequency bands proposed in IEEE 2800-2022”; and
- 10% voted in favor of “Retain currently proposed PRC-029 criteria”.

Following the technical conference, NERC staff, Standards Committee representatives, some members of the drafting team, and FERC staff met to discuss the results of the straw polls as well as previously reviewed material. The team discussed that the term “legacy assets”, as used during the technical conference, aligned with the date for seeking potential exemption within PRC-029-1; meaning those IBR that were “in-service” by the effective date of PRC-029-1. While respondents at the technical conference did vote more favorably to retaining existing PRC-024 criteria for legacy assets, other information submitted by commenters and highlighted during the panel of original equipment manufacturers, indicated that a significant majority of IBR have been designed to meet IEEE 2800-2022 values.[20, 21]

Additional information provided during the NERC staff presentation[22] identified that many IBR were still being designed and installed without setting their protection and controls in accordance with their physical capabilities. Due to a concern of lowering the bar of performance by requiring that IBR perform less than what the significant majority of IBR are being designed and manufactured to, it was determined that the proposed standard should not align with previous PRC-024-3 criteria.

Based on the more clearly understood hardware-based capability limitation established due to manufacture design for a significant amount of installed IBR, there was a reliability concern to proceed with Draft 3 PRC-029-1 frequency criteria as that same amount of IBR could necessitate disconnection and retrofitting in order to comply. It was also identified that the potential disconnection of a large amount of installed IBR capacity did not substantially outweigh unstudied reliability benefits potentially resulting from setting frequency ride-through bands wider than those established in IEEE 2800-2022 and overwhelmingly identified by manufacturers during our comment review when designing IBR throughout the past decade. Due to these reliability concerns, the frequency criteria in Attachment 2 of the draft has been adjusted to align with those values in IEEE 2800-2022.

Feasibility of Hardware-Based Exemptions from Frequency Ride-Through Requirements

Potential hardware-based exemptions were discussed during each formal comment period of PRC-029-1, with a significant majority of commenters supporting some exemptions from frequency ride-through

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[20] See Industry Submitted Comments for the Standards Committee & NERC Ride-through Technical Conference; Project 2020-02 Modifications to PRC-024 (Generator Ride-through) Related Files; posted September 2024.

[21] See Day 1 Recording and Transcript of the Standards Committee & NERC Ride-through Technical Conference; Project 2020-02 Modifications to PRC-024 (Generator Ride-through) Related Files; posted September 18, 2024.

[22] See “Review of Voltage and Frequency Ride-through” of posted Standards Committee and NERC Ride-through Technical Conference material; page 67/129.

criteria for legacy IBR. The drafting team and industry were advised that Order No. 901 only included and only allowed for exemptions of voltage ride-through performance requirements, based on the following discussion of allowable exemptions within the order:

> "Therefore, we direct NERC through its standard development process to determine whether the new or modified Reliability Standards should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements."[23]
>
> "Further, we direct NERC to ensure that any such exemption would be applicable for only existing equipment that is unable to meet voltage ride-through performance. When such existing equipment is replaced, the exemption would no longer apply, and the new equipment must comply with the appropriate IBR performance requirements specified in the Reliability Standards (e.g., voltage and frequency ride through, phase lock loop, ramp rates, etc.)." [24]

While the order spoke only to exemptions from voltage ride-through requirements and was silent regarding any exemptions for frequency ride-through criteria, industry continued to identify that there was a need to include such exemptions in PRC-029-1. It was determined that the details shared leading up to and during the technical conference provided clarity as well as a more substantiated basis for why hardware-based exemptions of frequency ride-through criteria was needed.

Prior to the technical conference, NERC solicited comments from industry as well as original equipment manufacturers.[25] In particular, any information on hardware-based limitations that would prevent IBR from meeting the proposed frequency criteria within PRC-029-1 was requested. 21 individual comments were received including six (6) from different original equipment manufacturers of IBR. NERC and representatives from the Standards Committee reviewed the submitted material and confirmed that IBR are being designed by original equipment manufacturers to be able to meet those voltage and frequency ride-through curves established in IEEE 2800-2022. As Draft 3 of PRC-029-1 proposed frequency criteria were beyond those established in IEEE 2800-2022, there was a concern that IBR would not be able to meet those proposed frequency criteria as IBR capability limits were hardware-based and inherent to a manufacturer's design.

While many comments received during the formal comment periods stressed a desire to align PRC-029-1 with IEEE 2800-2022, there was little differentiation between comments that sought to leverage other industry volunteer guidelines that have been significantly adopted with those comments that sought exemptions due to the fact that manufacturers are designing IBR capabilities to the IEEE 2800-2022 values. Moreover, comments submitted by manufacturers provided a better understanding and approximation of what percentage of the installed fleets of IBR would be unable to meet PRC-029-1 frequency criteria. While additional information regarding specific amounts of affected IBR is still sought by NERC, from the

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23 *See id*. at P 153.

24 *See id*. at P 153.

25 See Standards Committee and NERC Ride-through Technical Conference; Conference Details; publicly announced August 21, 2024; https://www.nerc.com/pa/Stand/Documents/SC_and_NERC%20Ride-through_Technical_Conference_Details_08212024.pdf

information provided, it appears that a significant percentage of IBR[26] – specifically Type 3 wind turbine facilities – would need to retrofit to avoid noncompliance with PRC-029-1 as proposed in Draft 3.

The technical conference included a panel discussion on frequency exemptions. Panelists discussed various challenges related to legacy IBR, such as difficulties obtaining more detailed information on equipment capabilities; specifically for manufacturers who are no longer in business and for IBR that are no longer supported by the manufacturer. In such instances, additional time and cost would be expected to conduct more detailed capability testing. Other concerns raised included the possibility that manufacturers would not be willing to provide design or hardware limitation documentation should they identify the information to be proprietary information. Other discussions substantiated information received during the solicitation of comments for the conference and provided more clarity as to the alignment of the IEEE 2800-2022 curves with inherent capability limitations.[27]

Following the technical conference, NERC staff, Standards Committee representatives, some members of the drafting team, and FERC staff met to discuss the discussions during the conference as well as previously reviewed material. Based on the more clearly understood hardware-based capability limitation established due to manufacture design for a significant amount of installed IBR, there was a reliability concern to proceed with no potential for hardware-based limitations for frequency criteria, as that same amount of IBR could necessitate disconnection and retrofitting to comply.

It was determined that this potential disconnection of a large amount of installed IBR capacity overwhelmingly indicated a reliability need to allow for a documented and limited set of exemptions for IBR from voltage and frequency ride-through criteria. In light of this reliability concern, Requirement R4 of PRC-029-1 has been modified to allow for a documented, and limited set of exemptions for IBR from frequency criteria. Further modifications were made to allow Generator Owners to exclude information considered to be proprietary from submittals to anyone other than the Compliance Enforcement Authority, to facilitate the sharing of requisite information from manufacturers.

Conclusion

After following the process described in Section 321 of the NERC Rules of Procedure, as directed by the NERC Board of Trustees at the August 15, 2024 meeting, proposed Reliability Standard PRC-029-1 has been revised to: include revised definition for the new proposed term "Ride-through", align frequency ride-through criteria with IEEE 2800-2022 values, allow for a limited documented set of exemptions for hardware-based limitations for frequency ride-through criteria, and to allow Generator Owners to only share information deemed by the original equipment manufacturer as proprietary with the Compliance Enforcement Authority..

These revisions in proposed Reliability Standard PRC-029-1 reflect a fulsome consideration of the technical, reliability, and implementation considerations raised in the underlying development proceeding and during

[26] Analysis of the data collected through NERC's Level 2 Alert: Industry Recommendation for IBR Performance Issues showed that the number of resources that are not able to meet PRC-029 Draft 3 is approximately double when compared to those same resources ability to comply with the updated criteria in PRC-029 Draft 4 which align with IEEE 2800-2022. Information submitted through the comment period and the technical conference discussions indicated that this ratio would be higher for wind resources, specifically Type 3 wind.

[27] See Day 2 Recording and Transcript of the Standards Committee & NERC Ride-through Technical Conference; Project 2020-02 Modifications to PRC-024 (Generator Ride-through) Related Files; posted September 18, 2024.

the technical conference, with the intent of addressing the Order No. 901 directives in a manner that is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified.

Unofficial Comment Form

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2020-02 Modifications to PRC-024 (Generator Ride-through)** by **8 p.m. Eastern, Monday, September 30, 2024.**

Additional information is available on the project page. If you have questions, contact Director of Standards Development, Jamie Calderon (email), or at 404-960-0568.

Background Information

The goal of Project 2020-02 is to mitigate the recent and ongoing disturbance ride-through performance issues identified across multiple Interconnections and numbers of disturbances analyzed by NERC and the Regions. These issues have been associated with Inverter-Based Resources (IBR) with many causes of their tripping or cessation unrelated to voltage and frequency protection settings requirements in the currently effective version of PRC-024 and PRC-024-3. Proposed Reliability Standard PRC-024-4 includes revisions to limit its applicability to synchronous generators and synchronous condensers only and remains as a protection-based standard. A new standard, PRC-029-1, is proposed as a true disturbance ride-through Reliability Standard with applicability to inverter-based resources.

In October 2023, FERC issued Order No. 901, which directed NERC to develop new or modified existing Reliability Standards that include new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. Project 2020-02 was one of three projects identified by NERC that must be completed and filed with FERC by November 4, 2024 to address Order No. 901 directives. At the December 2023 Standards Committee (SC) meeting, the SC approved waivers for Project 2020-02, allowing formal comment periods to be reduced from 45 days to 25 calendar days, and final ballot periods to be reduced from 10 days to as few as 5 calendar days.

On August 15, 2024, the NERC Board of Trustees (Board) invoked Section 321 of the NERC Rules of Procedure (ROP) to address critical and rapidly growing risk to the reliability of the Bulk Power System associated with inverter-based resources (IBR) in response to FERC Order No. 901 directives. PRC-029-1 (Frequency and Voltage Ride-through Requirements for Inverter-based Resources) is a draft standard designed to establish capability-based and performance-based Ride-through requirements for IBRs during grid disturbances. The draft standard failed to achieve consensus from the Registered Ballot Body over multiple ballots, calling into question whether development would be completed by FERC's filing deadline of November 4, 2024, which resulted in the Board acting under Section 321 of the ROP. Under this special authority, the Board directed the SC to work with NERC to host a technical conference and to ballot an additional ballot of PRC-029-1 within 45-days of the August 15 Board action.

<u>Questions</u>

1. Do you agree that the revisions accurately represent the changes discussed at the September Standards Committee and NERC Ride-through Technical Conference?

   ☐ Yes
   ☐ No

   Comments:

2. Provide any additional comments for consideration, if desired.

   Comments:

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Technical Rationale

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

PRC-029-1 – Frequency and Voltage Ride-through Requirements for Inverter-based Generating Resources

General Rationale

The drafting team has created a new Reliability Standard (PRC-029-1) to address inverter-based resource (IBR) disturbance Ride-through performance criteria. This proposal is a consequence of both the different natures of synchronous and inverter-based generation resources and several recent events exhibiting significant IBR Ride-through deficiencies[1]. The proposed PRC-029-1 aligns with certain Ride-through requirements of IEEE Std 2800™, IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems, primarily for frequency Ride-through, and is structured to follow language from FERC Order No. 901, which states that "NERC has the discretion to consider during its standards development process whether and how to reference IEEE standards in the new or modified Reliability Standards."[2]

The lack of standardization of IBR performance and the software-based nature of the technologies has created reliability challenges associated with the interconnection of IBR facilities to the power grid. The nature of the fast switching of power electronics of IBR generation, IBR's software-based nature, and the electronic interface to the transmission system is such that disturbance Ride-through behavior is largely determined by manufacturer-specific equipment and controls system designs. These controls may be programmed, but also have more restrictive limits on current, both in magnitude and duration. IBR responses to grid disturbances are highly controlled and managed by using fast switching of power electronics devices dependent upon manufacturer specific control system design software that can be programmed in many ways and with various and concurrent Ride-through performance objectives. Rather than attempting to restrict the myriad of control approaches, protections, and settings, it is more straightforward to require Ride-through during defined frequency and voltage excursions.

In contrast to synchronous generation, the need for IBR Ride-through requirements has been heightened by recent events during which IBRs have not met PRC-024-3 frequency and voltage Ride-through expectations, often due to controls and protection only indirectly associated with the system voltage and frequency excursions. In addition to Ride-through, there is the question of what IBRs should be doing as they Ride-through. IBR responses to system disturbances can be beneficial or detrimental to both their own Ride-through and system reliability, often depending on adjustable control settings. Thus, it is essential to set expectations on performance during Ride-through as well as Ride-through capability.

[1] Event Reports (nerc.com)
[2] P 195, FERC Order No. 901; https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false; October 17, 2023

A further reason for proposing a separate IBR standard is that the inertial and short circuit contributions from IBR are significantly different than synchronous machines. The drafting team thinks that IBRs should Ride through voltage and frequency excursions up to their maximum capability, while using expanded voltage and frequency Ride-through criteria to drive those enhancements. These differences between synchronous machines and IBR contribute to the differences in the frequency and voltage tables and graphs between the PRC-024-4 and PRC-029-1 standards.

The proposed PRC-029-1 must be understood generally as an event-based standard though it is also required to provide evidence of the ability to Ride-through disturbance events by means of dynamic models and simulation results. Compliance with PRC-029-1 is determined chiefly, though not exclusively, from IBR Ride-through performance during transmission system events in the field. An IBR becomes noncompliant with PRC-029-1 when an event in the field occurs that shows that one or more requirements were not satisfied. This intent is clarified by *Operations Assessment* as the Time Horizon designation of requirements R1-R3.

FERC Order No. 901 Directives

PRC-029-1 is proposed in consideration of directives from FERC Order No. 901 that were assigned to the Project 2020-02 drafting team. The following directives were assigned to this drafting team for inclusion in this standards project (paragraph numbers of the FERC Order are included for reference):

- Paragraph 190: “Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults.”
- Paragraph 190: “The new or modified Reliability Standards must require registered IBRs to continue to inject current and perform frequency support during a Bulk-Power System disturbance.”
- Paragraph 190: “Any new or modified Reliability Standard must also require registered IBR generator owners and operators to prohibit momentary cessation in the must Ride-through zone during disturbances.”
- Paragraph 190: “NERC must submit new or modified Reliability Standards that establish IBR performance requirements, including requirements addressing frequency and voltage ride through, post-disturbance ramp rates, phase lock loop synchronization, and other known causes of IBR tripping or momentary cessation.”
- Paragraph 193: “Therefore, we direct NERC through its standard development process to determine whether the new or modified Reliability Standards should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements.”

- Paragraph 193: "Further, we direct NERC to ensure that any such exemption would be applicable for only existing equipment that is unable to meet voltage Ride-through performance. When such existing equipment is replaced, the exemption would no longer apply, and the new equipment must comply with the appropriate IBR performance requirements specified in the Reliability Standards (e.g., voltage and frequency ride through, phase lock loop, ramp rates, etc.)."
- Paragraph 193: "Finally, we direct NERC, through its standard development process, to require the limited and documented exemption list (i.e., IBR generator owner and operator exemptions) to be communicated with their respective Bulk-Power System planners and operators (e.g., the IBR generator owner's or operator's planning coordinator, transmission planner, reliability coordinator, transmission operator, and balancing authority)."
- Paragraph 199: "Pursuant to section 215(d)(5) of the FPA, we modify the NOPR proposal. To the extent NERC determines that a limited and documented exemption for those registered IBRs currently in operation and unable to meet voltage Ride-through requirements is appropriate due to their inability to modify their coordinated protection and control settings, we direct NERC to develop new or modified Reliability Standards to mitigate the reliability impacts to the Bulk-Power System of such an exemption."
- Paragraph 208: "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop and submit to the Commission for approval new or modified Reliability Standards that require post-disturbance ramp rates for registered IBRs to be unrestricted and not programmed to artificially interfere with the resource returning to a pre-disturbance output level in a quick and stable manner after a Bulk-Power System."
- Paragraph 209: "The proposed new or modified Reliability Standards must require registered IBRs to ride through momentary loss of synchronism during Bulk-Power System disturbances and require registered IBRs to continue to inject current into the Bulk-Power System at pre-disturbance levels during a disturbance, consistent with the IBR Interconnection Requirements Guideline and Canyon 2 Fire Event Report recommendations."
- Paragraph 209: "Related to ACP/SEIA's comment recommending to revise the directive to require generators to maintain synchronism where possible and continue to inject current to support system stability, we direct NERC, through its standard development process, to consider whether there are conditions that may limit generators to maintain synchronism."
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- Paragraph 226: "Further, we believe that there is a need to have all of the directed Reliability Standards effective and enforceable well in advance of 2030 and direct NERC to ensure that the associated implementation plans sequentially stagger the effective and enforceable dates to ensure an orderly industry transition for complying with the IBR directives in this final rule prior to that date." (*pertains to multiple projects*)

Rationale for Applicability Section (4.0)

Functional Entities (4.1)

The functional entity responsible for assuring acceptable Ride-through performance of IBR is the Generator Owner.

Facilities (4.2)

Applicability Facilities include only IBR that also meet NERC registration criteria. Language used within PRC-029-1 applicability only refers to IBR as a whole plant/facility. Consistent with FERC Order No. 901, IBR performance is based on the overall IBR plant and disturbance monitoring equipment requirements established under the proposed PRC-028-1. Requirements within PRC-029-1 do not apply to individual inverter units or measurements taken at individual inverter unit terminals.

Rationale for Requirement R1

The objective of Requirement R1 is to ensure that all applicable IBRs will Ride-through grid voltage disturbances consistent with the must Ride-through zone and operation regions specified in **Attachment 1**. IBRs must be able to demonstrate Ride-through performance, that they remain electrically connected, i.e., shall not trip, and continue to exchange current, i.e., shall not enter momentary cessation.

The drafting team determined that the definition of “must Ride-through zones” and “operation regions” should be consistent with those terms as used within IEEE 2800-2022. Additionally, the team determined that the voltage thresholds of each operation region should be based on measurements taken on the high-side of the main power transformer in PRC-029-1, also consistent with IEEE 2800-2022.

Battery Energy Storage Systems (BESS) units also must comply with Requirement R1 in all operating modes including charging, discharging, and idle (energized, but not charging or discharging). A BESS in idle mode must be capable of responding to system voltage and frequency excursions as it does in charging or discharging modes.

Exceptions to **Attachment 1** performance criteria are allowable when 1) an IBR needs to trip to clear a fault, 2) voltage at the high-side of the main power transformer goes outside an accepted and a documented hardware equipment limitation established in accordance with Requirement R4, 3) instantaneous positive sequence voltage phase angle jumps more than 25 electrical degrees at the high-side of the main power transformer initiated by a non-fault switching events occur on the transmission system, or 4) volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

When a grid disturbance occurs, such as a close-in fault or a relatively large switching event, the grid voltage may experience a rapid phase angle shift. In such cases, the phase displacement $\Delta\theta$ can be large enough to pose challenges for the phase lock loop (PLL) to track the terminal voltage, cause control instability within the inverter, such as the inner current control loop or the DC link control loop, and even lead to tripping of the inverter due to the malfunction of the controls.

Since phase angle jumps are common occurrences on the BPS, this standard requires the IBR to be designed and operated to Ride-through a minimum phase angle jump of 25 electrical degrees. This is a typical value and aligns with the requirement in IEEE 2800-2022.

Some IBR equipment has PLL loss of synchronism protection, referring to a protective function that operates when the angle displacement $\Delta\theta$ exceeds a threshold for a predetermined period of time (on the order of a couple of milliseconds). Historically, this protection has been used by some inverter manufacturers, especially for inverters in distribution systems. For the IBR connected to the BPS, this protection function should be disabled. If it is enabled, the phase angle jump protection setting should be configured such that the IBR shall only trip to prevent equipment damage.

Rationale for Requirement R2

In addition to having minimum voltage Ride-through capability specified in Requirement R1, all applicable IBRs are also required to adhere to certain voltage Ride-through performance criteria during system disturbances. Acceptable performance criteria depend on the operation region that an IBR is presently in or when in transition from one operation region to another operation region. Requirement R2 includes specific performance criteria and is needed to assure consistent IBR performance within and each operation region in **Attachment 1** and when in transition between regions.

Rationale for Requirement R2.1

This subpart of Requirement R2 ensures that when the voltage at the high-side of the main power transformer (MPT) recovers to the continuous operation region from either the mandatory operation region or the permissive operation region, an IBR delivers the pre-disturbance level of Real Power or available Real Power, whichever is less. Available Real Power allows for changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes attributed to IBR tripping in whole or part. This requires an IBR to exit the “High Voltage Ride Through (HVRT)” or “Low Voltage Ridge Through (LVRT)” modes properly such that it does not cause reduction in the Real Power when the high-side of MPT voltage recovers to within the continuous operation region.

When the voltage at the high-side of the MPT is greater than 0.90 per-unit and less than 0.95 per-unit, IBRs are expected to exit the LVRT mode and come back to “normal operating mode”. If an IBR has a default total current limit of 1.0 per-unit, the apparent power production of an IBR will be limited below 1.0 per-unit (e.g., the per-unit value of IBR terminal voltage). In such case, the IBR needs to configure a preference setting, either to maintain pre-disturbance Real Power or maximize the Reactive Power in order to further help with voltage recovery, or according to requirements specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Rationale for Requirement R2.2

This subpart of Requirement R2 ensures that when the voltage at the high-side of the MPT is within the mandatory operation region, IBRs inject or absorb reactive current proportional to the level of terminal voltage deviations they measure. IBRs shall follow Transmission Planner, Planning Coordinator, Reliability

Coordinator, or Transmission Operator specified certain magnitude of Reactive Power response to voltage changes, if available.

By default, reactive current prioritization shall be configured unless Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires Real Power priority.

Rationale for Requirement R2.3

This subpart of Requirement R2 ensures that when the voltage at the high-side of the MPT is within the permissive operation region, IBRs continue to Ride-through, though they are briefly allowed to enter the current block mode if necessary to avoid tripping off from the grid. The drafting team takes into consideration the physical operational capability of the power electronics devices under such low voltage conditions. However, the IBR facility shall restart current exchange in less than or equal to five cycles of positive sequence voltage returning to the continuous operation region or mandatory operation region. If the interconnecting entity has performance requirements that are more stringent than the standard, the Generator Owner should follow the requirements set by the interconnecting entity.

Rationale for Requirement R2.4

This subpart of Requirement R2 ensures when a fault is cleared on the transmission system, the voltage regulators of connected IBRs must adjust the reactive current injection to restore the transmission system voltage to the pre-disturbance voltage as defined by the automatic voltage regulator (AVR) setpoint. The drafting team acknowledges that tuning of the AVR requires a balance between multiple competing physical factors, e.g., rise time, overshoot, and transient stability. However, it is anticipated that IBR controls will be tuned to allow for a stable post-disturbance voltage recovery without causing excessive overshoot or undershoot of the setpoint. When such overshoots do occur, they must not exceed the magnitude and duration of the applicable table given in **Attachment 1**. Furthermore, this standard anticipates that control system tuning to prevent such over/under voltages will focus on the speed at which the controller responds to setpoint changes rather than on the magnitude of the reactive current response. For example, reductions in k-factor to prevent over/under voltages should only be considered as a last resort.

Rationale for Requirement R2.5

This subpart of Requirement R2 ensures that the IBR returns to effective pre-disturbance operation unless otherwise specified or needed by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Rationale for Requirement R3

The objective of Requirement R3 is to ensure that IBRs Ride-through frequency excursion events with magnitude and time durations as defined in Attachment 2.

Grid frequency reflects the balance of system generation and load. A system event that causes a generation/load imbalance will cause system frequency to deviate from nominal. The system may experience an over-frequency event (in the case of more generation than load) or an under-frequency event (in the case of less generation than load). Inertia resists the deviation from nominal frequency, giving the operators additional time to rebalance generation and load. With the current resource mix, system inertia is dependent on the amount of rotating mass connected to the system (i.e., synchronous generators or motors). The larger the system inertia, the slower the system frequency will deviate from the nominal value and the lower the grid Rate Of Change Of Frequency (ROCOF), giving more time to try to rebalance generation and load.

A reduction in system inertia is an inevitable consequence of a power system transiting toward more IBR and less synchronous generators, however the utilization of IBR-specific control features (i.e., advanced control modes and Grid Forming technologies) can provide additional stability benefits to help mitigate the loss of inertia. As discussed in the previous paragraph, less system inertia means the frequency will deviate from the nominal value more quickly during a generation/load imbalance event and will expose the system to a higher ROCOF. A wider frequency Ride-through capability for IBR may be required to avoid the risk of widespread tripping.

When considering an expansion of Ride-through capability, it is important to balance the expansion with the feasibility of producing and installing equipment that can meet the newly proposed criteria. Failure to adequately consider this could result in resource adequacy deficiencies if expanded criteria lead to widespread non-compliance of legacy IBR due to hardware limitations. Further, for newly interconnecting IBR, expanded Ride-through criteria often result in significant design changes that have production time and cost implications. If proposed Ride-through criteria are too stringent and result in costly design changes, those costs could result in a slowing of IBR penetration on the BPS.

For the reasons above, it is imperative that newly created Ride-through criteria are reasonable for both BPS reliability and for the IBR equipment. To date, NERC has analyzed numerous major events including both winter storms Uri and Elliot. No IBR tripped offline for frequency threshold criteria (because the system frequency caused a trip due to exceeding equipment frequency limits) and all frequency-related tripping observed were due to mis-parameterization or the use of instantaneous measurements in protection schemes. Additionally, the deviations in frequency observed during the events listed above did not exceed the PRC-024 criteria. It should be noted that winter storm Uri did produce a frequency excursion extremely close to, and even touching, the criteria in PRC-024.

With no “benchmark events” to inform criteria expansions, studies could be used to assess future BPS needs. These studies would need a detailed list of scenarios, including different IBR penetrations and load levels, and are dependent on the ability to accurately model current and future IBR technologies, including GFM functions. NERC has issued two level 2 alerts related to IBR, one on IBR performance and the second on modeling. These alerts seek to obtain data from IBR while also giving recommendations to mitigate the observed systemic modeling and performance deficiencies of IBR. Given these observed deficiencies and the lack of recently conducted detailed system-wide studies, there is insufficient study-based evidence to inform widely expanded Ride-through criteria.

It is clear however that the performance of the BPS during disturbance will change as the IBR penetration increases. How this performance will change can be predicted with detailed studies, but an incremental approach to expanding Ride-through criteria adds additional stability margin while modeling deficiencies are addressed and detailed studies are conducted.

The frequency Ride-through times and thresholds in IEEE 2800-2022 are more stringent (wider) than those presently in PRC-024-3 and contain continuous operation ranges that exceed the frequency excursions observed during major BPS disturbances. Detailed feedback from original equipment manufacturers (OEM) provides insight that they are already designing IBR equipment that conforms with the criteria in IEEE 2800-2022. For this reason, the frequency Ride-through criteria in the PRC-029 standard are in alignment with those criteria in IEEE 2800-2022, which provides an expansion of Ride-through criteria compared to PRC-024 while also minimizing cost and timeline implications as OEM are already designing conforming equipment.

Requirement R3 does not prescribe specific frequency protection settings for IBR equipment. IBR frequency protection settings should only be set to protect the IBR from damage caused by operation at off-nominal frequency. An IBR owner must ensure that the IBR frequency protection does not prevent an IBR from meeting the R3 Ride-through requirement.

This standard requires that IBRs remain electrically connected and continue to exchange current during a frequency excursion event in which the frequency remains within the must Ride-through zone according to **Attachment 3** and while the absolute ROCOF magnitude is less than or equal to 5 Hz/second. Some IBR controllers and their ability to remain electrically connected and continue to exchange current with the grid are sensitive to ROCOF, particularly auxiliary equipment that are essential for IBR performance, during a frequency excursion event. If needed to maintain the stability of the IBR or prevent equipment damage, the R3 requirement allows the IBR to trip for an absolute ROCOF exceeding 5Hz/sec within the must Ride-through zone of **Attachment 2**. Failure to Ride-through due to ROCOF exceeding 5Hz/sec shall only be allowed during a generator/load imbalance event that causes the frequency to deviate from nominal.

To minimize the misoperation tripping of the IBR on the ROCOF setting, the rate of change of frequency (ROCOF) must be calculated as the average rate of change over multiple calculated system frequencies for some time greater than or equal to 0.1 seconds. The ROCOF calculation is not applicable during the fault occurrence and clearance (i.e., protection should not trip due to any perceived ROCOF during the entire disturbance and recovery period) and should not operate at the onset of a fault, during a fault, or at fault clearance, i.e., it should be disabled during faults. The IBR shall Ride-through any system disturbance while the voltage at the high-side of the main power transformer remains within the must Ride-through zones as specified in **Attachment 1**. The ROCOF measurement should begin after fault clearance and is only applicable for generation/load imbalance disturbances such as a system separation, an island condition, or the loss of a large load or generator.

Rationale for Requirement R4

The objective of Requirement R4 is to ensure legacy IBR (IBR existing as of the enforcement date of PRC-029-1) are able to obtain an exemption to the voltage and frequency Ride-through requirements if hardware replacements or other costly upgrades would be necessary to comply with Requirements R1 through Requirement R3. This provision allows such exemptions as long as such limitations are documented and communicated to the Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator of the respective footprints in which the IBR project is located. The Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator will then need to take the voltage Ride-through limitations into account in planning and operations.

Limitations must not be construed as complete exemptions from the applicable tables, but must be specific as to which voltage or frequency band(s) and associated duration(s) cannot be satisfied or specific as to the number of cumulative voltage deviations within a ten-second time period that the equipment can Ride-through if less than four. Limitation descriptions should identify the specific equipment and explain the characteristic(s) of that equipment that prevent Ride-through. If any equipment limitation is removed or otherwise corrected, it is likewise necessary to communicate to the Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator of this.

Technical Rationale

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

PRC-029-1 – Frequency and Voltage Ride-through Requirements for Inverter-based Generating Resources

General Rationale

The drafting team has created a new Reliability Standard (PRC-029-1) to address inverter-based resource (IBR) disturbance Ride-through performance criteria. This proposal is a consequence of both the different natures of synchronous and inverter-based generation resources and several recent events exhibiting significant IBR Ride-through deficiencies[1]. The proposed PRC-029-1 ~~coincides~~aligns with certain Ride-through requirements of IEEE Std 2800~~-2022 but~~™, IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems, primarily for frequency Ride-through, and is structured to follow language from FERC Order No. 901, which states that "NERC has the discretion to consider during its standards development process whether and how to reference IEEE standards in the new or modified Reliability Standards."[2]

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- Paragraph 209: "We direct NERC to submit to the Commission for approval new or modified Reliability Standards that would require registered IBRs to ride through any conditions not addressed by the proposed new or modified Reliability Standards that address frequency or voltage ride through, including phase lock loop loss of synchronism."
- Paragraph 226: "Further, we believe that there is a need to have all of the directed Reliability Standards effective and enforceable well in advance of 2030 and direct NERC to ensure that the associated implementation plans sequentially stagger the effective and enforceable dates to

ensure an orderly industry transition for complying with the IBR directives in this final rule prior to that date." (*pertains to multiple projects*)

Rationale for Applicability Section (4.0)

Functional Entities (4.1)

The functional entity responsible for assuring acceptable Ride-through performance of IBR is ~~either~~ the Generator Owner.

Facilities (4.2)

Applicability Facilities include only IBR that also meet NERC registration criteria. Language used within PRC-029-1 applicability only refers to IBR as a whole plant/facility. Consistent with FERC Order No. 901, IBR performance is based on the overall IBR plant and disturbance monitoring equipment requirements established under the proposed PRC-028-1. Requirements within PRC-029-1 do not apply to individual inverter units or measurements taken at individual inverter unit terminals.

Rationale for Requirement R1

The objective of Requirement R1 is to ensure that all applicable IBRs will Ride-through grid voltage disturbances consistent with the must Ride-through zone and operation regions specified in **Attachment 1**. IBRs must be able to demonstrate Ride-through performance, that they remain electrically connected, i.e., shall not trip, and continue to exchange current, i.e., shall not enter momentary cessation.

The drafting team determined that the definition of "must Ride-through zones" and "operation regions" should be consistent with those terms as used within IEEE 2800-2022. Additionally, the team determined that the voltage thresholds of each operation region should be based on measurements taken on the high-side of the main power transformer in PRC-029-1, also consistent with IEEE 2800-2022.

Battery Energy Storage Systems (BESS) units also must comply with Requirement R1 in all operating modes including charging, discharging, and idle (energized, but not charging or discharging). A BESS in idle mode must be capable of responding to system voltage and frequency excursions as it does in charging or discharging modes.

Exceptions to **Attachment 1** performance criteria are allowable when 1) an IBR needs to trip to clear a fault, 2) voltage at the high-side of the main power transformer goes outside an accepted and a documented hardware equipment limitation established in accordance with Requirement R4, 3) instantaneous positive sequence voltage phase angle jumps more than 25 electrical degrees at the high-side of the main power transformer initiated by a non-fault switching events occur on the transmission system, or 4) volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

When a grid disturbance occurs, such as a close-in fault or a relatively large switching event, the grid voltage may experience a rapid phase angle shift. In such cases, the phase displacement $\Delta\theta$ can be large enough to pose challenges for the phase lock loop (PLL) to track the terminal voltage, cause control instability within the inverter, such as the inner current control loop or the DC link control loop, and even lead to tripping of the inverter due to the malfunction of the controls.

Since phase angle jumps are common occurrences on the BPS, this standard requires the IBR to be designed and operated to Ride-through a minimum phase angle jump of 25 electrical degrees. This is a typical value and aligns with the requirement in IEEE 2800-2022.

Some IBR equipment has PLL loss of synchronism protection, referring to a protective function that operates when the angle displacement $\Delta\theta$ exceeds a threshold for a predetermined period of time (on the order of a couple of milliseconds). Historically, this protection has been used by some inverter manufacturers, especially for inverters in distribution systems. For the IBR connected to the BPS, this protection function should be disabled. If it is enabled, the phase angle jump protection setting should be configured such that the IBR shall only trip to prevent equipment damage.

Rationale for Requirement R2

In addition to having minimum voltage Ride-through capability specified in Requirement R1, all applicable IBRs are also required to adhere to certain voltage Ride-through performance criteria during system disturbances. Acceptable performance criteria depend on the operation region that an IBR is presently in or when in transition from one operation region to another operation region. Requirement R2 includes specific performance criteria and is needed to assure consistent IBR performance within and each operation region in **Attachment 1** and when in transition between regions.

Rationale for Requirement R2.1

This subpart of Requirement R2 ensures that when the voltage at the high-side of the main power transformer (MPT) recovers to the continuous operation region from either the mandatory operation region or the permissive operation region, an IBR delivers the pre-disturbance level of Real Power or available Real Power, whichever is less. Available Real Power allows for changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes attributed to IBR tripping in whole or part. This requires an IBR to exit the “High Voltage Ride Through (HVRT)” or “Low Voltage Ridge Through (LVRT)” modes properly such that it does not cause reduction in the Real Power when the high-side of MPT voltage recovers to within the continuous operation region.

When the voltage at the high-side of the MPT is greater than 0.90 per-unit and less than 0.95 per-unit, IBRs are expected to exit the LVRT mode and come back to “normal operating mode”. If an IBR has a default total current limit of 1.0 per-unit, the apparent power production of an IBR will be limited below 1.0 per-unit (e.g., the per-unit value of IBR terminal voltage). In such case, the IBR needs to configure a preference setting, either to maintain pre-disturbance Real Power or maximize the Reactive Power in order to further help with voltage recovery, or according to requirements specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Rationale for Requirement R2.2

This subpart of Requirement R2 ensures that when the voltage at the high-side of the MPT is within the mandatory operation region, IBRs inject or absorb reactive current proportional to the level of terminal voltage deviations they measure. IBRs shall follow Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specified certain magnitude of Reactive Power response to voltage changes, if available.

By default, reactive current prioritization shall be configured unless Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires Real Power priority.

Rationale for Requirement R2.3

This subpart of Requirement R2 ensures that when the voltage at the high-side of the MPT is within the permissive operation region, IBRs continue to Ride-through, though they are briefly allowed to enter the current block mode if necessary to avoid tripping off from the grid. The drafting team takes into consideration the physical operational capability of the power electronics devices under such low voltage conditions. However, the IBR facility shall restart current exchange in less than or equal to five cycles of positive sequence voltage returning to the continuous operation region or mandatory operation region. If the interconnecting entity has performance requirements that are more stringent than the standard, the Generator Owner should follow the requirements set by the interconnecting entity.

Rationale for Requirement R2.4

This subpart of Requirement R2 ensures when a fault is cleared on the transmission system, the voltage regulators of connected IBRs must adjust the reactive current injection to restore the transmission system voltage to the pre-disturbance voltage as defined by the automatic voltage regulator (AVR) setpoint. The drafting team acknowledges that tuning of the AVR requires a balance between multiple competing physical factors, e.g., rise time, overshoot, and transient stability. However, it is anticipated that IBR controls will be tuned to allow for a stable post-disturbance voltage recovery without causing excessive overshoot or undershoot of the setpoint. When such overshoots do occur, they must not exceed the magnitude and duration of the applicable table given in **Attachment 1**. Furthermore, this standard anticipates that control system tuning to prevent such over/under voltages will focus on the speed at which the controller responds to setpoint changes rather than on the magnitude of the reactive current response. For example, reductions in k-factor to prevent over/under voltages should only be considered as a last resort.

Rationale for Requirement R2.5

This subpart of Requirement R2 ensures that the IBR returns to effective pre-disturbance operation unless otherwise specified or needed by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Rationale for Requirement R3

The objective of Requirement R3 is to ensure that IBRs Ride--through frequency excursion events with magnitude and time durations as defined in Attachment 2.

Grid frequency reflects the balance of system generation and load. A system event that causes a generation/load imbalance will cause system frequency to deviate from nominal. The system may experience an over-frequency event (in the case of more generation than load) or an under-frequency event (in the case of less generation than load). Inertia resists the deviation from nominal frequency, giving the operators additional time to rebalance generation and load. ~~System~~ With the current resource mix, system inertia ~~depends~~is dependent on the amount of rotating mass connected to the system (~~such as the~~i.e., synchronous generators or motors). The larger the system inertia, the slower the system frequency will deviate from the nominal value and the lower the grid Rate Of Change Of Frequency (ROCOF), giving more time to try to rebalance generation and load. ~~Also, higher system inertia may minimize the risk of Cascading generation loss caused by the operation of generator frequency protection.~~

A reduction in system inertia is an inevitable consequence of a power system transiting toward more IBR and less synchronous generators~~.~~, however the utilization of IBR-specific control features (i.e., advanced control modes and Grid Forming technologies) can provide additional stability benefits to help mitigate the loss of inertia. As discussed in the previous paragraph, less system inertia means the frequency will deviate from the nominal value more quickly during a generation/load imbalance event and will expose the system to a higher ROCOF. A wider frequency Ride-through capability for IBR may be required to avoid the risk of widespread tripping. ~~To reduce the risk of widespread IBR tripping during frequency disturbances, and more generally to ensure the reliability of future grids with high IBR penetration, the drafting team proposes a 6-second frequency Ride-through capability requirement for frequencies in the ranges of 61.8Hz to 64Hz or 57.0Hz to 56.0Hz range. The proposed 6-second time frame of the frequency Ride-through capability requirement is beyond the IEEE 2800 standard frequency Ride-through requirement and beyond frequency Ride-through requirements for synchronous machines under PRC-024.~~

~~IBRs lack the inertia and short circuit contributions of synchronous machines. To compensate for the lack of inertia and short circuit contributions, they should have wider tolerances for frequency and voltage excursions to meet the needs of future power systems with a higher percentage of IBR. Synchronous resources are more sensitive to frequency deviations than IBR resources. All IBR resources (except for type 3 wind turbines) interface to the grid through fast switching of power electronics devices. These power electronic devices are much less sensitive to the transmission system frequency excursion than non-hydraulic turbine synchronous resources (steam turbines and combustion turbines). In the case of the non-hydraulic turbine synchronous resources, the turbine is usually considered to be more restrictive than the generator in limiting IBR frequency Ride-through because of possible mechanical resonances in the many stages of turbine blades. Off-nominal frequencies may bring blade vibrational frequencies closer to a mechanical resonate frequency and cause damage due to the vibration stresses. However, inverter-interfaced IBR does not share this vibrational failure mode. Therefore, IBR should be capable of riding through the increased proposed 6-second frequency Ride-through requirement without risk of equipment damage or need for frequency protection to operate.~~
When considering an expansion of Ride-through capability, it is important to balance the expansion with the feasibility of producing and installing equipment that can meet the newly proposed criteria. Failure to adequately consider this could result in resource adequacy deficiencies if expanded criteria lead to widespread non-compliance of legacy IBR due to hardware limitations. Further, for newly interconnecting

IBR, expanded Ride-through criteria often result in significant design changes that have production time and cost implications. If proposed Ride-through criteria are too stringent and result in costly design changes, those costs could result in a slowing of IBR penetration on the BPS.

For the reasons above, it is imperative that newly created Ride-through criteria are reasonable for both BPS reliability and for the IBR equipment. To date, NERC has analyzed numerous major events including both winter storms Uri and Elliot. No IBR tripped offline for frequency threshold criteria (because the system frequency caused a trip due to exceeding equipment frequency limits) and all frequency-related tripping observed were due to mis-parameterization or the use of instantaneous measurements in protection schemes. Additionally, the deviations in frequency observed during the events listed above did not exceed the PRC-024 criteria. It should be noted that winter storm Uri did produce a frequency excursion extremely close to, and even touching, the criteria in PRC-024.

With no “benchmark events” to inform criteria expansions, studies could be used to assess future BPS needs. These studies would need a detailed list of scenarios, including different IBR penetrations and load levels, and are dependent on the ability to accurately model current and future IBR technologies, including GFM functions. NERC has issued two level 2 alerts related to IBR, one on IBR performance and the second on modeling. These alerts seek to obtain data from IBR while also giving recommendations to mitigate the observed systemic modeling and performance deficiencies of IBR. Given these observed deficiencies and the lack of recently conducted detailed system-wide studies, there is insufficient study-based evidence to inform widely expanded Ride-through criteria.

It is clear however that the performance of the BPS during disturbance will change as the IBR penetration increases. How this performance will change can be predicted with detailed studies, but an incremental approach to expanding Ride-through criteria adds additional stability margin while modeling deficiencies are addressed and detailed studies are conducted.

The frequency Ride-through times and thresholds in IEEE 2800-2022 are more stringent (wider) than those presently in PRC-024-3 and contain continuous operation ranges that exceed the frequency excursions observed during major BPS disturbances. Detailed feedback from original equipment manufacturers (OEM) provides insight that they are already designing IBR equipment that conforms with the criteria in IEEE 2800-2022. For this reason, the frequency Ride-through criteria in the PRC-029 standard are in alignment with those criteria in IEEE 2800-2022, which provides an expansion of Ride-through criteria compared to PRC-024 while also minimizing cost and timeline implications as OEM are already designing conforming equipment.

Requirement R3 does not prescribe specific frequency protection settings for IBR equipment. IBR frequency protection settings should only be set to protect the IBR from damage caused by operation at off-nominal frequency. An IBR owner must ensure that the IBR frequency protection does not prevent an IBR from meeting the R3 Ride-through requirement.

This standard requires that IBRs remain electrically connected and continue to exchange current during a frequency excursion event in which the frequency remains within the must Ride-through zone according to **Attachment 3** and while the absolute ROCOF magnitude is less than or equal to 5 Hz/second. Some IBR controllers and their ability to remain electrically connected and continue to exchange current with the grid are sensitive to ROCOF, particularly auxiliary equipment that are essential for IBR performance, during a frequency excursion event. If needed to maintain the stability of the IBR or prevent equipment damage, the R3 requirement allows the IBR to trip for an absolute ROCOF exceeding 5Hz/sec within the must Ride-through zone of **Attachment 2**. Failure to Ride-through due to ROCOF exceeding 5Hz/sec shall only be allowed during a generator/load imbalance event that causes the frequency to deviate from nominal.

To minimize the misoperation tripping of the IBR on the ROCOF setting, the rate of change of frequency (ROCOF) must be calculated as the average rate of change over multiple calculated system frequencies for some time greater than or equal to 0.1 seconds. The ROCOF calculation is not applicable during the fault occurrence and clearance (i.e., protection should not trip due to any perceived ROCOF during the entire disturbance and recovery period) and should not operate at the onset of a fault, during a fault, or at fault clearance, i.e., it should be disabled during faults. The IBR shall Ride-through any system disturbance while the voltage at the high-side of the main power transformer remains within the must Ride-through zones as specified in **Attachment 1**. The ROCOF measurement should begin after fault clearance and is only applicable for generation/load imbalance disturbances such as a system separation, an island condition, or the loss of a large load or generator.

Rationale for Requirement R4

The objective of Requirement R4 is to ensure legacy IBR (IBR existing as of the enforcement date of PRC-029-1) are able to obtain an exemption to the voltage and frequency Ride-through requirements if hardware replacements or other costly upgrades would be necessary to comply with Requirements R1 ~~or~~through Requirement ~~R2~~R3. This provision allows such exemptions as long as such limitations are documented and communicated to the Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator of the respective footprints in which the IBR project is located. The Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator will then need to take the voltage Ride-through limitations into account in planning and operations.

Limitations must not be construed as complete exemptions from the applicable ~~**Attachment 1** table~~tables, but must be specific as to which voltage or frequency band(s) and associated duration(s) cannot be satisfied or specific as to the number of cumulative voltage deviations within a ten-second time period that the equipment can Ride-through if less than four. Limitation descriptions should identify the specific equipment and explain the characteristic(s) of that equipment that prevent Ride-through. If any equipment limitation is removed or otherwise corrected, it is likewise necessary to communicate to the Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator of this.

~~FERC Order No. 901 states that this provision would be limited to exempting “certain registered IBRs from voltage Ride-through performance requirements.” This is the reason that no similar provisions are included for exemptions for frequency or ROCOF Ride-through requirements per R3.~~

Violation Risk Factor and Violation Severity Level Justifications

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
PRC-029-1

This document provides the drafting team's (DT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-029-1. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The DT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Power System (BPS) instability, separation, or a cascading sequence of failures, or could place the BPS at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to BPS instability, separation, or a cascading sequence of failures, or could place the BPS at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the BPS, or the ability to effectively monitor and control the BPS. However, violation of a medium risk requirement is unlikely to lead to BPS instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BPS, or the ability to effectively monitor, control, or restore the BPS. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BPS instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the BPS, or the ability to effectively monitor and control the BPS; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BPS, or the ability to effectively monitor, control, or restore the BPS.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the BPS. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BPS:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for PRC-029-1, Requirement R1	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate as applicable generating resources must be able to ride-through system disturbances. Failure to ride-through has been documented in multiple NERC reports leading to exacerbated system conditions, resulting in the electrical disconnecting of additional generation and widespread outages.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Similar requirements in PRC-024-3 are identified as Medium but are based on equipment protection setting documentation rather than actual, recorded performance during a grid disturbance. Therefore, this VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner failed to ensure the design capability of each applicable IBR to Ride-through in accordance with Attachment 1, except for those conditions identified in Requirement R1.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to Ride-through requirements in accordance with Attachment 1, except for those conditions identified in Requirement R1.

VSL Justifications for PRC-029-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R1	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R2	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate as applicable generating resources must be able to ride-through system disturbances. Failure to ride-through has been documented in multiple NERC reports leading to exacerbated system conditions, resulting in the electrical disconnecting of additional generation and widespread outages.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Similar requirements in PRC-024-3 are identified as Medium but are based on equipment protection setting documentation rather than actual, recorded performance during a grid disturbance. Therefore, this VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-029-1, Requirement R2	
Proposed VRF	**High**
Definitions of VRFs	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner failed to ensure the design capability of each applicable IBR to adhere to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.

VSL Justifications for PRC-029-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for PRC-029-1, Requirement R2	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R3	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of High is appropriate that if violated, it would be expected to adversely affect the electrical state or capability of the BPS.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner IBR to ensure the design capability of each applicable IBR to Ride-through in accordance with Attachment 2,	N/A	N/A	The Generator Owner IBR to ensure each applicable IBR adhered to Ride-through requirements in accordance with Attachment 2,

unless a documented hardware limitation exists in accordance with Requirement R4.			unless a documented hardware limitation exists in accordance with Requirement R4.

VSL Justifications for PRC-029-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for PRC-029-1, Requirement R3	
Number of Violations	

VRF Justifications for PRC-029-1, Requirement R4	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate that if violated, it would not be expected to adversely affect the electrical state or capability of the BPS.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of Lower VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a Lower VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 12 months but less than or equal to 15 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 90 days but less than or equal to 120 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 90 days but less than or equal to 120 days after receiving the acceptance of a hardware limitation by the CEA. OR The Generator Owner with a previously communicated hardware limitation that replaces	The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 120 days but less than or equal to 150 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 120 days but less than or equal to 150 days after receiving the acceptance of a hardware limitation by the CEA. OR The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 120 calendar days but less than or	The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 150 days but less than or equal to 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 150 days but less than or equal to 180 days after receiving the acceptance of a hardware limitation by the CEA. OR The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 150 calendar days but less than or	The Generator Owner failed to document complete information for IBR identified with known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1 or R2. OR The Generator Owner failed to provide a copy to the applicable entities as detailed in Requirement R4.2 within 24 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 180 days after receiving the acceptance of a hardware limitation by the CEA.

VSLs for PRC-029-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and CEA more than 90 calendar days but less than or equal to 120 calendar days after the change to the hardware.	equal to 150 calendar days after the change to the hardware.	equal to 180 calendar days after the change to the hardware.	OR The Generator Owner failed to document complete information for IBR identified with known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1 or R2.

VSL Justifications for PRC-029-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R4	
Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

Violation Risk Factor and Violation Severity Level Justifications

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
PRC-029-1

This document provides the drafting team's (DT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-029-1. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The DT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Power System (BPS) instability, separation, or a cascading sequence of failures, or could place the BPS at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to BPS instability, separation, or a cascading sequence of failures, or could place the BPS at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the BPS, or the ability to effectively monitor and control the BPS. However, violation of a medium risk requirement is unlikely to lead to BPS instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BPS, or the ability to effectively monitor, control, or restore the BPS. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BPS instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the BPS, or the ability to effectively monitor and control the BPS; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BPS, or the ability to effectively monitor, control, or restore the BPS.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the BPS. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BPS:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for PRC-029-1, Requirement R1	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate as applicable generating resources must be able to ride-through system disturbances. Failure to ride-through has been documented in multiple NERC reports leading to exacerbated system conditions, resulting in the electrical disconnecting of additional generation and widespread outages.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Similar requirements in PRC-024-3 are identified as Medium but are based on equipment protection setting documentation rather than actual, recorded performance during a grid disturbance. Therefore, this VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner failed to ensure the design capability of each applicable IBR to Ride-through in accordance with Attachment 1, except for those conditions identified in Requirement R1.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to Ride-through requirements in accordance with Attachment 1, except for those conditions identified in Requirement R1.

VSL Justifications for PRC-029-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R1	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R2	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate as applicable generating resources must be able to ride-through system disturbances. Failure to ride-through has been documented in multiple NERC reports leading to exacerbated system conditions, resulting in the electrical disconnecting of additional generation and widespread outages.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Similar requirements in PRC-024-3 are identified as Medium but are based on equipment protection setting documentation rather than actual, recorded performance during a grid disturbance. Therefore, this VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-029-1, Requirement R2	
Proposed VRF	**High**
Definitions of VRFs	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner failed to ensure the design capability of each applicable IBR to adhere to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.

VSL Justifications for PRC-029-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for PRC-029-1, Requirement R2	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R3	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of High is appropriate that if violated, it would be expected to adversely affect the electrical state or capability of the BPS.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner IBR to ensure the design capability of each applicable IBR to Ride-through in accordance with Attachment 2,	N/A	N/A	The Generator Owner IBR to ensure each applicable IBR adhered to Ride-through requirements in accordance with Attachment 2,

unless a documented hardware limitation exists in accordance with Requirement R4.			unless a documented hardware limitation exists in accordance with Requirement R4.

VSL Justifications for PRC-029-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for PRC-029-1, Requirement R3	
Number of Violations	

VRF Justifications for PRC-029-1, Requirement R4	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate that if violated, it would not be expected to adversely affect the electrical state or capability of the BPS.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of Lower VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a Lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 12 months but less than or equal to 15 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 90 days but less than or equal to 120 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 90 days but less than or equal to 120 days after receiving the acceptance of a hardware limitation by the CEA. OR The Generator Owner with a previously communicated hardware limitation that replaces	The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 120 days but less than or equal to 150 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 120 days but less than or equal to 150 days after receiving the acceptance of a hardware limitation by the CEA. OR The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 120 calendar days but less than or	The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 150 days but less than or equal to 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 150 days but less than or equal to 180 days after receiving the acceptance of a hardware limitation by the CEA. OR The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 150 calendar days but less than or	The Generator Owner failed to document complete information for IBR identified with known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1 or R2. OR The Generator Owner failed to provide a copy to the applicable entities as detailed in Requirement R4.2 within 24 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 180 days after receiving the acceptance of a hardware limitation by the CEA.

VSLs for PRC-029-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and CEA more than 90 calendar days but less than or equal to 120 calendar days after the change to the hardware.	equal to 150 calendar days after the change to the hardware.	equal to 180 calendar days after the change to the hardware.	OR The Generator Owner failed to document complete information for IBR identified with known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1 or R2.

VSL Justifications for PRC-029-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R4	
Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

Violation Risk Factor and Violation Severity Level Justifications

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
PRC-029-1

This document provides the drafting team's (DT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-029-1. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The DT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to Bulk Power System (BPS) instability, separation, or a cascading sequence of failures, or could place the BPS at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to BPS instability, separation, or a cascading sequence of failures, or could place the BPS at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the BPS, or the ability to effectively monitor and control the BPS. However, violation of a medium risk requirement is unlikely to lead to BPS instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BPS, or the ability to effectively monitor, control, or restore the BPS. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BPS instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the BPS, or the ability to effectively monitor and control the BPS; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BPS, or the ability to effectively monitor, control, or restore the BPS.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the BPS. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BPS:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for PRC-029-1, Requirement R1	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate as applicable generating resources must be able to ride-through system disturbances. Failure to ride-through has been documented in multiple NERC reports leading to exacerbated system conditions, resulting in the electrical disconnecting of additional generation and widespread outages.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Similar requirements in PRC-024-3 are identified as Medium but are based on equipment protection setting documentation rather than actual, recorded performance during a grid disturbance. Therefore, this VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner failed to ensure the design capability of each applicable IBR to Ride-through in accordance with Attachment 1, except for those conditions identified in Requirement R1.	N/A	N/A	The Generator Owner failed to ~~demonstrate~~ ensure each applicable IBR adhered to Ride-through requirements in accordance with Attachment 1, except for those conditions identified in Requirement R1.

VSL Justifications for PRC-029-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-029-1, Requirement R1	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R2	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate as applicable generating resources must be able to ride-through system disturbances. Failure to ride-through has been documented in multiple NERC reports leading to exacerbated system conditions, resulting in the electrical disconnecting of additional generation and widespread outages.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Similar requirements in PRC-024-3 are identified as Medium but are based on equipment protection setting documentation rather than actual, recorded performance during a grid disturbance. Therefore, this VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-029-1, Requirement R2	
Proposed VRF	**High**
Definitions of VRFs	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner failed to ~~demonstrate~~ ensure the design capability of each applicable IBR to adhere to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.	N/A	N/A	The Generator Owner failed to ~~demonstrate~~ ensure each applicable IBR adhered to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.

VSL Justifications for PRC-029-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for PRC-029-1, Requirement R2	
Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-029-1, Requirement R3	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of High is appropriate that if violated, it would be expected to adversely affect the electrical state or capability of the BPS.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a High VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner IBR to ~~demonstrate~~ ensure the design capability of each applicable IBR to Ride-through in accordance with	N/A	N/A	The Generator Owner IBR to ~~demonstrate~~ ensure each applicable IBR adhered to Ride-through requirements in

Attachment 2, unless a documented hardware limitation exists in accordance with Requirement R4.			accordance with Attachment 2, unless a documented hardware limitation exists in accordance with Requirement R4.

VSL Justifications for PRC-029-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for PRC-029-1, Requirement R3	
Number of Violations	

VRF Justifications for PRC-029-1, Requirement R4	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate that if violated, it would not be expected to adversely affect the electrical state or capability of the BPS.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of Lower VRF is consistent with the VRF assignments for other requirements in the proposed Reliability Standard. This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a Lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VSLs for PRC-029-1, Requirement R4

Lower	Moderate	High	Severe
~~The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and CEA more than 90 calendar days but less than or equal to 120 calendar days after the change to the hardware.~~ ~~OR~~ The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 12 months but less than or equal to 15 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 90 days but less than or equal to 120 days after receiving a request for additional information	~~The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 120 calendar days but less than or equal to 150 calendar days after the change to the hardware.~~ ~~OR~~ The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 15 months, but less than or equal to 18 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 120 days but less than or equal to 150 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.	~~The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 150 calendar days but less than or equal to 180 calendar days after the change to the hardware.~~ ~~OR~~ The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 18 months, but less than or equal to 24 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 150 days but less than or equal to 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1.	The Generator Owner failed to document complete information for IBR identified with known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1, R2, ~~-~~or R3~~2~~. ~~OR~~ ~~The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s),Reliability Coordinator(s), and CEA more than 180 calendar days after the change to the hardware.~~ OR The Generator Owner failed to provide a copy to the applicable entities as detailed in Requirement R4.2 within 24 months after the effective date of Requirement R4. OR

VSLs for PRC-029-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 90 days but less than or equal to 120 days after receiving the acceptance of a hardware limitation by the CEA. OR The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and CEA more than 90 calendar days but less than or equal to 120 calendar days after the change to the hardware.	OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 120 days but less than or equal to 150 days after receiving the acceptance of a hardware limitation by the CEA. OR The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 120 calendar days but less than or equal to 150 calendar days after the change to the hardware.	OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 150 days but less than or equal to 180 days after receiving the acceptance of a hardware limitation by the CEA. OR The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 150 calendar days but less than or equal to 180 calendar days after the change to the hardware.	The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 180 days after receiving the acceptance of a hardware limitation by the CEA. OR The Generator Owner with a previously communicated hardware limitation that replace the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s),Reliability Coordinator(s), and CEA more than 180 days after the change to the hardware.

VSL Justifications for PRC-029-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

Standards Development Consideration of Directives from FERC Order 901

June 2024

Background

The Federal Energy Regulatory Commission (FERC) issued Order No. 901 on October 19, 2023, which includes directives on new or modified NERC Reliability Standard projects. Order No. 901 addresses a wide spectrum of reliability risks to the grid from the application of inverter-based resources (IBR); including both utility scale and behind the-meter or distributed energy resources. Within the Order, are four milestones that include sets of directives to NERC. The first milestone was achieved on January 17, 2024 as NERC filed its initial work plan to address all aspects of Order No. 901 throughout the next three years.[1] The filed work plan includes extensive detail on Standards Development approach and next steps to accomplish the suite of directives addressing IBR. The work plan was intended to be an initial roadmap to guide development for each of the Reliability Standards Projects identified as a 901-related project.

This document includes specifics for how each directive assigned to Project 2020-02 Modifications to PRC-024 (Generator Ride-through) drafting team have been addressed.

Resources

[FERC Order No. 901 – Final Rule Reliability Standards to Address Inverter-Based Resources]

[NERC Mapping Document for FERC Order 901 Directives to Standards Development Projects, Draft SARs, and Pending SARs]

[1] INFORMATIONAL FILING OF THE NORTH AMERICAN RELIABILITY CORPORATION REGARDING THE DEVELOPMENT OF RELIABILITY STANDARDS RESPONSIVE TO ORDER NO. 901; 01/17/2024; https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/NERC%20Compliance%20Filing%20Order%20No%20901%20Work%20Plan_packaged%20-%20public%20label.pdf

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
49	190	2	"Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	The new standard PRC-029-1 will require registered generator owners of IBRs to both design and operate their IBR plants to ride through voltage and frequency excursions within "must ride-through zones" according to how these zones are defined in the standard. The must ride-through zones are defined in terms of voltage and frequency magnitude and time duration. Tripping of IBR plants is permitted only outside of the defined must ride-through zones. The voltage and frequency must ride-through zones are based on IEEE 2800-2022 no-trip zones and are established in view of experience with voltage and frequency excursions in planning and operating criteria disturbances, under-frequency load shedding stages, reasonable and practical limits of IBR voltage and frequency tolerances, PRC-024-3 voltage and frequency relay setting graphs, and include adequate margins against worst-case conditions that could be brought about during system disturbances.
50	190	2	"The new or modified Reliability Standards must require registered IBRs to continue to inject current and perform frequency support during a Bulk-Power System disturbance."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	In association with the new PRC-029 standard, a definition of the term *ride-through* is proposed for addition to the NERC Glossary of Terms that essentially states that IBR facilities must remain connected and continue to fulfill their established control and regulation functions (which generally involve exchange of current) in order to qualify as riding through system disturbances. Support of frequency is predicated on, and to a large degree achieved by the riding through of system disturbances. Frequency regulation (or governing) is presently not a continent-wide necessity and not a requirement on individual generating

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
					plants/facilities in NERC standards. RTO/ISO requirements may apply.
51	190	2	"Any new or modified Reliability Standard must also require registered IBR generator owners and operators to prohibit momentary cessation in the no-trip zone during disturbances."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	Momentary cessation, understood as inverter temporary current blocking while still remaining connected, is restricted to only two system conditions: 1) non-fault line switching caused voltage phase angle jumps in excess of 25 degrees that could result in tripping unless the inverter goes into current blocking, and 2) while voltage at the plant-system interface is less than 0.10 per unit during which time it may be difficult or impractical to maintain current exchange.
52	190	2	"NERC must submit new or modified Reliability Standards that establish IBR performance requirements, including requirements addressing frequency and voltage ride through, post-disturbance ramp rates, phase lock loop synchronization, and other known causes of IBR tripping or momentary cessation."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	IBR frequency and voltage ride through requirements are established in the new PRC-029 standard as noted above. A default post-disturbance ramp rate of 1.0 second is specified unless a faster or slower rate is specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator to accommodate specific system post-disturbance recovery needs. Any Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specified ramp rate becomes the standard requirement. Tripping due to phase lock loop loss of synchronism is specifically not permitted within voltage and frequency must ride through zones.
53	193	2	"Therefore, we direct NERC through its standard development process to determine whether the new or modified Reliability	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	Exemption from the voltage must ride-through zone requirement of PRC-029-1 is permitted for IBR plants/facilities that are in service at the enforcement date of the standard. The IBR Generator Owner must document the need for an exemption and the documentation must explain what hardware prevents the IBR

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
			Standards should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements."		from meeting the requirement and must be specific as to what aspect of the voltage must ride-through zone cannot be met. The Compliance Enforcement Authority checks that all aspects of the documentation specified in the standard have been provided by the GO and the GO is required to supply further information on the need for and the nature of the exemption if requested by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator. The implementation plan provides a 12-month time window for exemption requests to be submitted following the enforcement date. Following the 12-month window, further exemption requests will either not be accepted or could be considered an admission of non-compliance.
54	193	2	"Further, we direct NERC to ensure that any such exemption would be applicable for only existing equipment that is unable to meet voltage ride-through performance. When such existing equipment is replaced, the exemption would no longer apply, and the new equipment must comply with the appropriate IBR performance requirements specified in the Reliability Standards (e.g., voltage and frequency ride	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	The exemption provision of PRC-029-1 is available only for IBR plants/facilities that are in service at the enforcement date as noted above. The exemption provision also stipulates that once the plant/facility hardware causing the inability to comply with the voltage must ride-through requirement is replaced, the exemption is withdrawn ("no longer applies").

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
			through, phase lock loop, ramp rates, etc.)."		
55	193	2	"Finally, we direct NERC, through its standard development process, to require the limited and documented exemption list (i.e., IBR generator owner and operator exemptions) to be communicated with their respective Bulk-Power System planners and operators (e.g., the IBR generator owner's or operator's planning coordinator, transmission planner, reliability coordinator, transmission operator, and balancing authority)."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	The exemption provision of PRC-029-1 requires an IBR Generator Owner to supply its exemption request documentation to its Transmission Planner, Planning Coordinator, Reliability Coordinator, and Transmission Operator within the 12-month window following the enforcement date as noted above.

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
56	199	2	"Pursuant to section 215(d)(5) of the FPA, we modify the NOPR proposal. To the extent NERC determines that a limited and documented exemption for those registered IBRs currently in operation and unable to meet voltage ride-through requirements is appropriate due to their inability to modify their coordinated protection and control settings, we direct NERC to develop new or modified Reliability Standards to mitigate the reliability impacts to the Bulk-Power System of such an exemption."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	Mitigation of the reliability impacts of voltage must ride-through exemptions are existing NERC standard responsibilities of Transmission Planners, Planning Coordinators, Reliability Coordinators, and Transmission Operators under TPL, IRO, TOP, and other standards. These entities may need to restrict the operation of exempted IBRs where and when their tripping may result in detrimental reliability impacts.
57	208	2	"Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop and submit to the Commission for approval new or modified Reliability Standards that require post-disturbance ramp rates for registered IBRs to be unrestricted and not	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	As indicated above, a default post-disturbance ramp rate of 1.0 second is specified unless a faster or slower rate is specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator to accommodate specific system post-disturbance recovery needs. Any Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specified ramp rate becomes the standard requirement.

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
			programmed to artificially interfere with the resource returning to a pre-disturbance output level in a quick and stable manner after a Bulk-Power System."		
59	209	2	"We direct NERC to submit to the Commission for approval new or modified Reliability Standards that would require registered IBRs to ride through any conditions not addressed by the proposed new or modified Reliability Standards that address frequency or voltage ride through, including phase lock loop loss of synchronism."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	Phase lock loop loss of synchronism is not allowed as a cause of tripping while voltage remains within the must ride-through zone unless there are phase jumps more than 25 degrees caused by non-fault switching events. A footnote under R1 also specifically states that phase lock loop loss of synchronism as not a permissible condition for tripping while voltage remains within the must ride-through zone.
60	209	2	"The proposed new or modified Reliability Standards must require registered IBRs to ride through momentary loss of synchronism during Bulk-Power System disturbances and require registered IBRs to continue to inject current into the Bulk-	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	As indicated above, tripping due to phase lock loop loss of synchronism is specifically not permitted within voltage and frequency must ride-through zones. The requirement to return to pre-disturbance power also includes a provision for return to "available active power" to allow for "changes of facility active power output attributed to factors such as weather patterns, change of wind, and change in irradiance," but "changes of facility active power attributed to IBR tripping in

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
			Power System at pre-disturbance levels during a disturbance, consistent with the IBR Interconnection Requirements Guideline and Canyon 2 Fire Event Report recommendations."		whole or part" are not permitted. Injecting current at pre-disturbance levels during a disturbance is not always practical or desirable. PRC-029-1 R2 specifies IBR required active and reactive power performance during voltage disturbances.
61	209	2	"Related to ACP/SEIA's comment recommending to revise the directive to require generators to maintain synchronism where possible and continue to inject current to support system stability, we direct NERC, through its standard development process, to consider whether there are conditions that may limit generators to maintain synchronism."	Project 2020-02 Modifications to PRC-024 (Generator Ride-through)	IBRs are non-synchronous but can exhibit forms of instability other than loss of synchronism. System stability is a shared responsibility of Transmission Planners, Planning Coordinators, Reliability Coordinators, and Transmission Operators. IBR generation levels may need to be restricted by these entities to maintain system stability including IBR stability.
63A	226	2	"Further, we believe that there is a need to have all of the directed Reliability Standards effective and enforceable well in advance of 2030 and direct NERC to ensure that the associated implementation plans	Each of the identified Reliability Standards Projects in Milestone 2 will include implementation plans that assure	The PRC-029-1 implementation is a staggered implementation beginning twelve months following governmental approval with enforcement of all provisions within the twelve months following approval except as necessary to coordinate with the PRC-028-1 implementation plan that extends to 2030.

Index	Paragraph of Order	Milestone	Directive Subpart Summary	Active Project # Draft SAR # or Pending SAR name	Description of How This Directive has Been Addressed
			sequentially stagger the effective and enforceable dates to ensure an orderly industry transition for complying with the IBR directives in this final rule prior to that date."	all new or modified Reliability Standards are effective and enforceable before 2030.	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

Formal Comment Period Open through September 30, 2024

Now Available

A formal comment period for **PRC-029-1 - Frequency and Voltage Ride-through Requirements for Inverter-based Resources**, is open through **8 p.m. Eastern, Monday, September 30, 2024**.

On August 15, 2024, the NERC Board of Trustees (Board) invoked Section 321 of the NERC Rules of Procedure (ROP) to address critical and rapidly growing risk to the reliability of the Bulk Power System associated with inverter-based resources (IBR) in response to FERC Order No. 901 directives. PRC-029-1 (Frequency and Voltage Ride-through Requirements for Inverter-based Resources) is a draft standard designed to establish capability-based and performance-based Ride-through requirements for IBRs during grid disturbances. The draft standard failed to achieve consensus from the Registered Ballot Body over multiple ballots, calling into question whether development would be completed by FERC's filing deadline of November 4, 2024, which resulted in the Board acting under Section 321 of the ROP. Under this special authority, the Board directed the Standards Committee to work with NERC to host a technical conference and to ballot an additional ballot of PRC-029-1 within 45-days of the August 15 Board action.

The Standards Committee approved waivers to the Standard Processes Manual at their December 2023 meeting. These waivers were sought by NERC Standards staff for reduced formal comment and ballot periods. This will assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 901. FERC Order 901 was issued under Docket No. RM22-12-000 on October 19, 2023.

Note: PRC-024-4 passed the recent additional ballot (conducted June 28 – July 8, 2024). This standard will move to a final ballot when the PRC-029-1 ballots open (September 24-30, 2024) as only non-substantive revision(s) were made.

Reminder Regarding Corporate RBB Memberships
Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Commenting
Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps
Additional ballots for the standard and implementation plan, as well as the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **September 24-30, 2024.**

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Director of Standards Development, Jamie Calderon (via email) or at 404-960-0568. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2020-02 Modifications to PRC-024 (Generator Ride-through) observer list” in the Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2020-02 Modifications to PRC-024 (Generator Ride-through) | Draft 4 - PRC-029-1
Comment Period Start Date:	9/17/2024
Comment Period End Date:	10/4/2024
Associated Ballots:	2020-02 Modifications to PRC-024 (Generator Ride-through) Implementation Plan AB 4 OT 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-029-1 AB 4 ST

There were 58 sets of responses, including comments from approximately 150 different people from approximately 100 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree that the revisions accurately represent the changes discussed at the September Standards Committee and NERC Ride-through Technical Conference?

2. Provide any additional comments for consideration, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO

					Peter Brown	Invenergy	5,6	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Joshua Phillips	Southwest Power Pool	2	MRO
					Patrick Tuttle	Oklahoma Municipal Power Authority	4,5	MRO
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group, Inc.	3	RF
					Michelle Hribar	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
					Candace Morakinyo	WEC Energy Group, Inc.	4	RF
Dane Rogers	Dane Rogers			OG&E	Terri Pyle	OGE Energy - Oklahoma Gas and Electric Co.	1	MRO
					Donald Hargrove	OGE Energy - Oklahoma Gas and Electric Co.	3	MRO
					Patrick Wells	OGE Energy - Oklahoma Gas and Electric Co.	5	MRO
					Ashley F Stringer	OGE Energy - Oklahoma Gas and Electric Co.	6	MRO
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NPCC,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Kris Carper	Arizona Electric Power	1	WECC

						Cooperative, Inc.		
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Jolly Hayden	East Texas Electric Cooperative, Inc.	NA - Not Applicable	Texas RE
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC

Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Travis Grablander	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC

					David Kwan	Ontario Power Generation	4	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC
					Erin Wilson	NB Power	1	NPCC
					James Grant	NYISO	2	NPCC
					Michael Couchesne	ISO-NE	2	NPCC
					Kurtis Chong	IESO	2	NPCC
					Michele Pagano	Con Edison	4	NPCC
					Bendong Sun	Bruce Power	4	NPCC
					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
					Chantal Mazza	Hydro Quebec	1	NPCC

					Nicolas Turcotte	Hydro Quebec	2	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Victoria Crider	Dominion Energy	3	NA - Not Applicable
					Sean Bodkin	Dominion Energy	6	NA - Not Applicable
					Steven Belle	Dominion Energy	1	NA - Not Applicable
					Barbara Marion	Dominion Energy	5	NA - Not Applicable
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

1. Do you agree that the revisions accurately represent the changes discussed at the September Standards Committee and NERC Ride-through Technical Conference?

Jeffrey Streifling - NB Power Corporation - 1

Answer	No
Document Name	

Comment

The broad alignment of the technical requirements of PRC-029-1 with IEEE-2800-2022 represents the changes discussed at the NERC Ride-through Technical Conference; however, the wording of Footnote 10 to Tables 1 and 2 in Attachment 1 of PRC-029-1 Draft 4 appears to disallow the subcycle transient overvoltage tripping permitted in Section 7.2.3 and Figure 11 of IEEE 2800-2022 in a manner that could unnecessarily complicate the process of overvoltage coordination.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

See FirstEnergy's Q2 response.

We feel there are still unclear intentions and obligations under this standard.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy's view is that the Technical Conference reinforced stakeholder comments from the multiple previous comment periods for this project, which generally noted that an exception process was necessary due to the technical infeasibility of implementing the prescribed ride through criteria on existing inverters. The common theme at the technical conference was that OEMs need sufficient time periods to design, engineer, and produce equipment that is compliant with new regulatory requirements. OEMs stated that they are currently in the process of integrating IEEE2800-2022 criteria into devices, but that this process takes on average five years or more. Accordingly, it is unclear when PRC-029-1-compliant devices will become commercially available. While Dominion Energy supports Project 2020-02's goal of mitigating disturbance ride-through performance issues, Generator Owners that are developing public policy mandated, reliability-enhancing, clean energy projects will not have a path to compliance until PRC-029-1 compliant devices become commercially available.

Dominion Energy recognizes the positive changes made by NERC staff in the current version of PRC-029-1, however, the new limited exceptions process for commissioned IBR devices does not address projects that are in active development, with already contracted inverters that are not technically capable of meeting the proposed PRC-029-1 criteria. For IBR projects with extended lead times, like large offshore wind projects, equipment was contracted for and designed multiple years ago and may not be commissioned until after the effective date of the proposed PRC-029-1. NERC's failure to address this technical feasibility issue in the current draft could result in large amounts of clean, reliable energy that has been mandated by public policy being put at risk.

Dominion Energy recommends that the NERC Board of Trustees adhere to its Section 321 mandate, which it exercised for this proposed Standard, and remand PRC-029-1 back for further revisions so that it can approve a version that, as required under Section 321, subsection 5.2, "is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System,…".

To achieve this goal, Dominion Energy recommends expanding the exception criteria set forth in Requirement 4 to include IBRs that are already contracted. Additionally, until PRC-029-1 compliant devices are readily available commercially for the applicable project (e.g. Solar vs. Wind), exceptions should be permitted for these projects.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	No
Document Name	

Comment

Black Hills Corporation agrees with both NAGF and EEI, in that: PRC-029 Draft 4 does not address important concerns identified during the Technical Conference regarding software limits, balance of plant equipment issues, and the need to consider exemptions for IBR facilities that are in the procurement process (i.e. "in flight"). Additionally, we are concerned that Requirement R4 overlooks the impacts to GOs who are developing large, multi-year IBR projects that may not be completed by the effective date of this Reliability Standard. Resource equipment specifications are typically locked down at the time the interconnection agreement is signed, and a change in requirements/specifications after that point can require changes in the design of the equipment that are impossible to achieve without triggering a material modification, resulting in interconnection restudies and delaying or potentially canceling the project

Likes 0	
Dislikes 0	

Response

Michael Goggin - Grid Strategies LLC - 5	
Answer	No
Document Name	
Comment	

1. We appreciate the two significant changes in the latest draft of PRC-029-1: revision of R3 and R4 to add a hardware limitation exemption from frequency ride-through requirements for existing resources, and adoption of frequency ride-through curves in Attachment 2 that properly balance reliability needs with the capabilities of IBRs. As explained at length in the discussion of R3 in the updated Technical Rationale document, these changes properly balance reliability needs by ensuring resources will ride through disturbances while also avoiding resource adequacy concerns that could result from unnecessarily stringent requirements forcing the premature retirement of existing IBRs or preventing new IBRs from interconnecting.{C}[1] Retention of those two changes is essential for this standard to be workable, and for it to improve and not impede electric reliability. Because those two changes significantly improve the standard, we are voting for the revised standard, with the ask that the important clarifications and changes to the Implementation Plan discussed below be made. These changes are necessary to address serious concerns that were raised at the September 4-5, 2024, Ride-through Technical Conference regarding the effective date of the Standard and the evidence requirements for demonstrating a hardware limitation. These concerns are not adequately addressed in the current draft of the Standard or Implementation Plan.

2. We are seriously concerned that the revision to R4 we have requested in all three PRC-029-1 comment periods has not been adopted: R4 should allow hardware limitation exemptions for IBRs that have signed interconnection agreements, and not just IBRs that are in-service, as of the effective date of the standard. This change is needed because resource equipment decisions are typically locked down at the time the interconnection agreement is signed, and a change in requirements after that point can require a costly change in equipment or settings that may also trigger a material modification and resulting interconnection restudies. In certain cases, the IBR performance requirements referenced in the fully executed interconnection agreement contradict the NERC PRC-029 requirements.

The Implementation Plan for PRC-029 indicates that the effective date for the Standard will be the first day of the first quarter twelve months after FERC approval. Many resources take significantly longer than that to move from a signed interconnection agreement to being placed in service, so R4 should allow equipment limitation exemptions for resources that have a signed interconnection agreement as of the effective date of the Standard. This concern is explained at greater length in the comments Orsted submitted in this formal comment period on September 20, 2024.

This need can be most directly addressed by revising the first sentence of R4 to read "Each Generator Owner identifying an IBR that **has signed a Generator Interconnection Agreement** by the effective date of PRC-029-1…," with the bolded language above replacing "is in-service."

Alternatively, if NERC believes that there is no time for revisions to the draft of PRC-029-1, the Implementation Plan can be revised to make the effective date 48 months after regulatory approval of PRC-029-1 (and 36 months after the effective date for other BES resources) for offshore wind and other resources that can demonstrate that they require a long lead time between when equipment is procured and the plant is brought into service, instead of 12 months after regulatory approval as proposed for all BES resources in the Implementation Plan. The current draft of the Implementation Plan already proposes different compliance dates for BES and non-BES resources, so adding a third category for offshore wind and other Bulk Electric System IBRs with a long lead time for plant completion should not cause concern.

This change can be incorporated by adding language similar to the following in the Implementation Plan under the heading PRC-029-1 Phased-in Compliance Dates: "***Offshore wind and other Bulk Electric System IBRs with a long lead time for plant completion***: Entities shall comply with the portion of Requirements R1, R2, and R3 relating to the **design** of their BES IBRs to meet the requirements by 36 months after the effective date of the standard."

In light of the significant improvements in this draft standard, and to draw attention to this important unresolved issue that can be addressed by revising the Implementation Plan, we are voting for the proposed standard but against the Implementation Plan.

We would note that the Implementation Plan needs revision anyway, due to the apparently inadvertent inclusion of the following section at the end of the document. This section is inconsistent with the revision of the standard to include a hardware exemption from frequency ride-through requirements for existing resources, and thus should be removed or significantly revised:

Equipment Limitations and Process for Requirement R4

Consistent with FERC Order No. 901, a limited and documented exemption for some legacy IBR with certain documented equipment limitations are acceptable. Per the Order, these IBRs are

"…typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements."

To ensure compliance with Requirement R4 and alignment with FERC Order No. 901, only those IBR that are in operation as of the effective date of PRC-029-1 may be considered for potential exemption. Further, only those IBR that are unable to meet voltage ride-through requirements due to their inability to modify their coordinated protection and control settings may be considered for potential exemption.

3. NERC should clarify that existing equipment that has received an exemption from ride-through requirements due to a hardware limitation will not lose that exemption if separate new equipment is added at that plant. For example, adding a battery to an existing solar or wind plant that has received a hardware limitation exemption would not remove the exemption for the existing solar or wind equipment, though the new battery and its associated power conversion equipment would not be exempt from PRC-029-1's ride-through requirements. In that example, the existing wind or solar equipment would only lose the exemption if it and its associated power conversion equipment were replaced with new equipment. If NERC adopts the solution proposed above to revise the first sentence of R4 PRC-029-1 to allow hardware limitation exemptions for IBRs that have signed interconnection agreements (and not just IBRs that are in-service) as of the effective date of the standard, it must also clarify that a subsequent amendment to the interconnection agreement to allow the addition of separate new equipment does not remove the exemption for the existing equipment. These clarifications are important to ensure that PRC-029-1 does not impede the addition of separate new equipment at existing sites to expand their capability to provide energy, capacity, and other reliability services. If a revision to PRC-029-1 is not feasible at this point, an addition to the Implementation Plan or issuance of a Compliance Guidance document could help clarify this point.

4. As documented in Section C of the comments Orsted submitted in this formal comment period on September 20, 2024, additional clarification and consideration is needed to respect hardware limitations that may prevent both new HVDC- and AC-connected offshore wind plants from meeting some aspects of PRC-029-1. The proposal above to provide offshore wind and other long lead-time resources 48 months following regulatory approval to meet PRC-029-1 may not provide sufficient time for the offshore wind industry to develop technology solutions to meet these aspects of the PRC-029-1 requirements, so additional consideration for these hardware limitations will likely be needed. While offshore wind manufacturers are working to improve ride-through capability to meet IEEE 2800 and PRC-029-1, at least some new HVDC-connected offshore wind plants cannot meet the cumulative voltage ride-through requirements because consecutive fault events can overheat the DC chopper, posing a safety concern. Similarly, some AC-connected IBRs cannot meet the voltage or frequency ride-through requirements because the plants include synchronous condensers, which are designed to meet PRC-024-3.

If a revision to PRC-029-1 is not feasible at this point, an addition to the Implementation Plan or issuance of a Compliance Guidance document could help clarify these issues. For example, NERC could clarify that for new and existing IBRs, plant-level hardware limitations to meeting PRC-029-1 due to use of synchronous condensers within a plant are allowed if the synchronous condenser meets PRC-024. Similarly, NERC could clarify that, until adequate technology is developed, hardware limitations will be respected for new and existing offshore wind plants that cannot meet the cumulative voltage ride-through requirements of PRC-029-1, if the Planning Coordinator and Transmission Provider interconnecting that plant are informed of that limitation and determine that the plant can be reliably interconnected and operated.

In light of the significant improvements in this draft standard, and to draw attention to this important unresolved issue that can likely be addressed by revising the Implementation Plan or issuing a Compliance Guidance document, we are voting for the proposed standard but against the Implementation Plan. As noted above, the section entitled **Equipment Limitations and Process for Requirement R4** of the Implementation Plan already requires significant revision or removal, so that section could be repurposed to provide these important clarifications.

5. NERC should clarify the evidence requirements for demonstrating a hardware limitation in R4 and M4, potentially through a revision to the standard, an addition to the Implementation Plan, or by issuing a Compliance Guidance document. NERC should clarify that a resource can demonstrate a hardware limitation with a declaration or attestation from a manufacturer stating that the equipment was designed to meet the standards in place at the time it was installed and was not designed to meet the more rigorous standard proposed in PRC-029-1. As manufacturers explained at length at the September Ride-through Technical Conference, it is often challenging if not impossible to prove the negative that a piece of equipment cannot meet a requirement it was not designed to meet. Physical testing of operating equipment outside of a laboratory is often impractical or excessively costly, particularly for resources that have been operating for many years with varying degrees of degradation. In many cases the manufacturer of IBR equipment or its components no longer supports those legacy models, or the manufacturer may no longer be in business. Instead, it is much more practical for manufacturers to provide a positive attestation regarding the requirements the equipment was designed to meet.

Relatedly, NERC should clarify that the type of positive attestation discussed above is sufficient for meeting section 4.1.4 of R4, which calls for "Supporting Technical documentation verifying the limitation is due to hardware that would need to be physically replaced to meet all Ride- through criteria, and that the limitation cannot be removed by software updates or setting changes…". As discussed at the technical workshop, it is difficult to prove the negative that software or settings changes alone cannot remove a limitation.

In light of the significant improvements in this draft standard, and to draw attention to this important unresolved issue that can be addressed by revising the Implementation Plan or by issuing a Compliance Guidance document, we are voting for the proposed standard but against the Implementation Plan. As noted above, the section entitled **Equipment Limitations and Process for Requirement R4** of the Implementation Plan already requires significant revision or removal, so that section could be repurposed to provide these important clarifications.

{C}[1]{C} https://www.nerc.com/pa/Stand/202002_Transmissionconnected_Resources_DL/2020-02_PRC-029-1_Technical_Rationale_09172024.pdf, at 7: *When considering an expansion of Ride-through capability, it is important to balance the expansion with the feasibility of producing and installing equipment that can meet the newly proposed criteria. Failure to adequately consider this could result in resource adequacy deficiencies if expanded criteria lead to widespread non-compliance of legacy IBR due to hardware limitations. Further, for newly interconnecting IBR, expanded Ride-through criteria often result in significant design changes that have production time and cost implications. If proposed Ride-through criteria are too stringent and result in costly design changes, those costs could result in a slowing of IBR penetration on the BPS.*

For the reasons above, it is imperative that newly created Ride-through criteria are reasonable for both BPS reliability and for the IBR equipment. To date, NERC has analyzed numerous major events including both winter storms Uri and Elliot. No IBR tripped offline for frequency threshold criteria (because the system frequency caused a trip due to exceeding equipment frequency limits) and all frequency-related tripping observed were due to mis-parameterization or the use of instantaneous measurements in protection schemes. Additionally, the deviations in frequency observed during the events listed above did not exceed the PRC-024 criteria.

Likes 0	
Dislikes 0	
Response	
Maozhong Gong - GE - GE Wind - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

GE Vernova's Onshore Wind business is a leading wind turbine original equipment manufacturer (OEM) with over 75GW of wind turbines installed in North America. We appreciate the opportunity NERC has provided to submit comments to PRC-029-1 Draft 4. We appreciated the opportunity to participate in the Technical Conference in Washington, DC, on September 4- 5. The discussions promoted by NERC are extremely critical to develop appropriate regulations to set minimum IBR performance requirements to support the needs of the electrical system. While GE Vernova's Onshore Wind Business recognizes that important changes were made in Draft 4 to reflect the comments discussed during the Technical Conference, including frequency ride-through requirement alignment with IEEE 2800-2020, allowance of exemption for frequency ride-through requirement and others, there are still concerns which we believe are important to restate through these comments. Please refer to comments on Question 2.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

The NAGF supports the proposed changes to PRC-029 Draft 4 Requirements R3 and R4 that provide the frequency ride-through exemption for hardware limitation associated with existing resources. In addition, the NAGF supports the revised of frequency ride-through curves in Attachment 2. However, the PRC-029 Draft 4 does not address important concerns identified during the Technical Conference regarding software limits, balance of plant equipment issues, and the need to consider exemptions for IBR facilities that are in the procurement process (i.e. "in flight").

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

The SDT failed to address industry concerns related to ROCOF capabilities. The SDT should be reminded of comments provided by industry and the equipment manufacturer panelists during the technical conference that ROCOF requirements listed in R3 may not be able to be met by the legacy equipment. As many pointed out, the ROCOF capability may not be known at the present time and that lab and field testing potentially must be done to prove the capabilities. Even though R3 is added to R4, it will be very difficult to provide evidence for hardware limitation related to ROCOF. In addition, past IBR disturbance reports did not identify rate of change of frequency being an issue during the disturbances, it is not part of FERC order 901. Therefore there is no technical rationale to include it.

The SDT failed to address concerns from equipment manufacturer panelists about phase jump requirement listed in R1. Panelists expressed concern about differences between IEEE-2800 wording and PRC-029 wording. As confirmed by panelist, the inverter cannot differentiate between a non-fault switching event and a fault event as both can trigger the phase jump angle to increase.

The SDT failed to address concerns from equipment manufacturer panelists about 1 cycle voltage measurement filtering requirements.

Likes 0	
Dislikes 0	

Response

Brian Lindsey - Entergy - 1	
Answer	No
Document Name	
Comment	
We concur with the comments NAGF provided.	
Likes 0	
Dislikes 0	
Response	

Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	
NRG supports the proposed changes to PRC-029 Draft 4 Requirements R3 and R4 that provide the frequency ride-through exemption for hardware limitation associated with existing resources. In addition, NRG supports the revised of frequency ride-through curves in Attachment 2. However, the PRC-029 Draft 4 does not address important concerns identified during the Technical Conference regarding software limits, balance of plant equipment issues, and the need to consider exemptions for IBR facilities that are currently in the procurement process.	
Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
NRG is in alignment with NAGF's comments regarding the changes discussed at the Technical Conference. Although we support the proposed changes, the PRC-029 Draft 4 does not address important concerns identified during the Technical Conference regarding software limits, balance of plant equipment issues, and the need to consider exemptions for IBR facilities that are in the procurement process (i.e. “in flight”).	
Likes 0	
Dislikes 0	
Response	

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	No
Document Name	
Comment	
Vistra supports comments made by NRG Energy.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
NIPSCO supports the proposed changes to PRC-029 Draft 4 Requirements R3 and R4 that provide the frequency ride-through exemption for hardware limitation associated with existing resources. In addition, NIPSCO supports the revised frequency ride-through curves in Attachment 2. However, NIPSCO also supports the comments of the NAGF that the PRC-029 Draft 4 does not address important concerns identified during the Technical Conference regarding software limits, balance of plant equipment issues, and the need to consider exemptions for IBR facilities that are in the procurement process (i.e. “in flight”).	
Likes 0	
Dislikes 0	
Response	
Keith Smith - Orsted Americas - 5	
Answer	No
Document Name	
Comment	
Orsted and associated vendors provided comments to NERC prior to the technical conference that were not discussed during the technical conference and are not addressed in the latest version of the Standard.	
Likes 0	
Dislikes 0	

Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	

Invenergy would like to thank the Standard Drafting Team (SDT), the Standards Committee, and NERC management for their work on this standard and the organization of the ride-through technical conference. The technical conference was an excellent example of the unique rulemaking collaboration between regulators and industry afforded by the NERC Rules of Procedure, and we are encouraged by the significant revisions made in response to discussions at the conference. That said, there remain some problematic requirements that don't reflect the understanding reached at the technical conference regarding the alignment of PRC-029-1 criteria with Generator Owner and OEM capabilities.

Requirement R4

Invenergy believes the most effective way to address remaining industry concerns surrounding limited exceptions and the exceptions process is to carry over the language from Requirement R3 of PRC-024-3 (now PRC-024-4). As we noted in our comments on previous ballots and at the technical conference, FERC recommend this path in paragraph 193 of Order 901, stating, "We encourage NERC's standard drafting team to consider currently effective Reliability Standard PRC-024-3, Requirement R3 as an example for establishing registered IBR technology exemptions." Absent adoption of the same or similar language, we have the following suggestions to implement to more accurately represent the changes discussed at the technical conference.

The revisions to Requirement R4 to include limited exemptions from the frequency ride-through requirements due to hardware limitations are greatly appreciated and introduce a path to compliance for legacy IBRs that may be unable to meet the ride-through criteria that was not provided in earlier drafts of PRC-029-1. Still, many aspects of Requirement R4, identified below, are overly prescriptive and cause the path to compliance to be unreasonable to impossible to fulfill.

- **"In-service":** The ability for an IBR to apply for a limited exemption should not be based on the in-service date of that IBR for a few reasons. 1) In-service is not a defined term in NERC's Glossary of Terms and is used inconsistently across various NERC materials. 2) It fails to consider the fact that equipment procurement occurs years, oftentimes many years, prior to an IBR being placed in-service or achieving commercial operations. If a threshold date must be established, Invenergy recommends using the execution date of the Generator Interconnection Agreement, which would ensure that equipment procured years before the effective date of PRC-029-1 is not held to ride-through requirements it may not have been designed to meet. Additionally, it should be clarified that any subsequent amendment to the Generator Interconnect Agreement that incorporates new generation resources does not void any previously approved exemption for the existing equipment associated with that Generator Interconnection Agreement.

- **R4.1:** 12 months may be insufficient time to collect all the required documentation, much of which cannot be independently provided by the Generator Owner. To the extent an OEM can identify the specific piece(s) of hardware causing the limitation, extensive analysis and/or laboratory testing may require more time than the currently allotted 12 months. Invenergy fails to see the benefit of requiring this documentation be provided within a prescribed timeframe – the limitation will still exist regardless of whether all the intricacies are documented within 12 months – and recommends this time requirement be removed or extended to a minimum of 24 months.

- **R4.1.3 & R4.1.4:** As attested by many OEMs at the technical conference, it may be exceedingly difficult to impossible to identify the specific piece(s) of hardware causing a ride-through capability limitation. The hardware limitation could be the result of a combination of factors with several unknowns and interdependencies on auxiliary equipment that could not be validated by either the Generator Owner or the OEM. Even in situations where the OEM still supports a legacy model, the necessary testing to validate its capabilities vis-a-vis the requirements of PRC-029-1 is unfeasible, cost prohibitive, and may divert resources away from current or future product lines designed to meet more stringent ride-through requirements. Simply put, existing IBRs were developed and installed to meet the ride-through standards effective at that time and requirements, like R4.1.3 and R4.1.4, that effectively mandate a complete re-testing of the capabilities of each component and subcomponent should be removed.

- **R4.2:** Requirement R4.2 and the additional detail provided in Footnote 11 impose an unreasonable expectation that the Generator Owner share material it does not own and that is considered to be proprietary by the OEM. Invenergy recommends the removal of Footnote 11.

Attachment 1, Note 10: To date, Invenergy has not received any response from the SDT regarding our comments on Attachment 1, Note 10, which were submitted in response to Draft 2 and Draft 3 of PRC-029-1. Further, Invenergy and OEM comments on this matter at the technical conference are not reflected in Draft 4 of PRC-029-1.

Attachment 1 Note 10 is vague and subjects equipment to potential damage. Paragraphs 179 and 190 of FERC Order 901 establish that IBR tripping shall be permitted when necessary to protect the IBR equipment. Many protection decisions must be made in a matter of micro-seconds, and as drafted, Note 10 would adversely impact reliability by subjecting equipment to potentially damaging surges of current or voltage that near instantaneous protection settings are designed to mitigate. Can the SDT clarify if this requirement applies at the inverter level? If this requirement is to be applied at the plant level, note 10 should be amended to reflect that.

Likes 0	
Dislikes 0	

Response

Nick Leathers - Ameren - Ameren Services - 1,3,5,6 - MRO,SERC

Answer	No
Document Name	

Comment

Please correct the 1.1 per-unit voltage threshold row in table 1 to be greater than 1.1 rather than greater than or equal to match table 2.

The technical rationale states, "An IBR becomes noncompliant with PRC-029-1 when an event in the field occurs that shows that one or more requirements were not satisfied. This intent is clarified by the Operations Assessment as the Time Horizon designation of requirements R1-R3". This statement suggests that if a plant fails to ride through, it can become a self-report. Is it FERC's intent that entities are to self-report if a PRC-029 study of the design shows compliance, but field data indicates otherwise? We suggest updating the technical rationale to clarify this part.

Ameren also supports EEI and NAGF's comments.

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5

Answer	No
Document Name	

Comment

Comments: Invenergy would like to thank the Standard Drafting Team (SDT), the Standards Committee, and NERC management for their work on this standard and the organization of the ride-through technical conference. The technical conference was an excellent example of the unique rulemaking collaboration between regulators and industry afforded by the NERC Rules of Procedure, and we are encouraged by the significant revisions made in response to discussions at the conference. That said, there remain some problematic requirements that don't reflect the understanding reached at the technical conference regarding the alignment of PRC-029-1 criteria with Generator Owner and OEM capabilities.

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The revisions to Requirement R4 to include limited exemptions from the frequency ride-through requirements due to hardware limitations are greatly appreciated and introduce a path to compliance for legacy IBRs that may be unable to meet the ride-through criteria that was not provided in earlier drafts of PRC-029-1. Still, many aspects of Requirement R4, identified below, are overly prescriptive and cause the path to compliance to be unreasonable to impossible to fulfill.

- **"In-service":** The ability for an IBR to apply for a limited exemption should not be based on the in-service date of that IBR for a few reasons. 1) In-service is not a defined term in NERC's Glossary of Terms and is used inconsistently across various NERC materials. 2) It fails to consider the fact that equipment procurement occurs years, oftentimes many years, prior to an IBR being placed in-service or achieving commercial operations. If a threshold date must be established, Invenergy recommends using the execution date of the Generator Interconnection Agreement, which would ensure that equipment procured years before the effective date of PRC-029-1 is not held to ride-through requirements it may not have been designed to meet. Additionally, it should be clarified that any subsequent amendment to the Generator Interconnect Agreement that incorporates new generation resources does not void any previously approved exemption for the existing equipment associated with that Generator Interconnection Agreement.

- **R4.1:** 12 months may be insufficient time to collect all the required documentation, much of which cannot be independently provided by the Generator Owner. To the extent an OEM can identify the specific piece(s) of hardware causing the limitation, extensive analysis and/or laboratory testing may require more time than the currently allotted 12 months. Invenergy fails to see the benefit of requiring this documentation be provided within a prescribed timeframe – the limitation will still exist regardless of whether all the intricacies are documented within 12 months – and recommends this time requirement be removed or extended to a minimum of 24 months.

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Likes 0

Dislikes 0

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer No

Document Name

Comment

The broad alignment of the technical requirements of PRC-029-1 with IEEE-2800-2022 represents the changes discussed at the NERC Ride-through Technical Conference; however, the wording of Footnote 10 to Tables 1 and 2 in Attachment 1 of PRC-029-1 Draft 4 appears to disallow the sub cycle transient overvoltage tripping permitted in Section 7.2.3 and Figure 11 of IEEE 2800-2022 in a manner that could unnecessarily complicate the process of overvoltage coordination.

Likes 0

Dislikes 0

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer No

Document Name

Comment

OPG supports NPCC Regional Standards Committee’s comments.

Likes 0

Dislikes 0

Response

Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	No
Document Name	
Comment	

PNM Agrees with comments of EEI:

- EEI appreciates the revisions to PRC-029-1 and generally agrees that the changes align with many aspects of the discussions held during the NERC Technical Ride-through Conference. However, we are concerned that Requirement R4 overlooks the impacts to GOs who are developing large, multi-year IBR projects that may not be completed by the effective date of this Reliability Standard. Resource equipment specifications are typically locked down at the time the recourse contracts are finalized, and a change in requirements/specifications after that point can require changes in the design of the equipment that are impossible to achieve without triggering a material modification, resulting interconnection restudies and delaying or potentially canceling the project. To address this concern, we suggest the following modifications be made to Requirement R4 (in boldface below).

R4. Each Generator Owner identifying an IBR that is in-service or has a contract for an IBR that is in effect by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting Ride- through criteria as detailed in Requirements R1-R3, and requires an exemption from specific Ride-through criteria shall:10 *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

The revisions appear to reflect some of the viewpoints presented at the conference, but not others.

Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	

Duke Energy endorses and requests the incorporation of EEI comments.	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
The voltage ride-through requirements are more restrictive than PRC-024 and will require additional studies to determine whether existing IBR facilities are compliant. Both the standard and the implementation plan require compliance within 12 months after the effective date of PRC-029-1. This is not sufficient time to have studies completed and if needed, obtain additional documentation from IBR manufacturers, and submit that data to the Planning Coordinator, Transmission Planner, Transmission Operator, Reliability Coordinator and Compliance Enforcement Authority. A minimum of three years should be allowed.	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
The voltage ride-through requirements are more restrictive than PRC-024 and will require additional studies to determine whether existing IBR facilities are compliant. Both the standard and the implementation plan require compliance within 12 months after the effective date of PRC-029-1. This is not sufficient time to have studies completed and if needed, obtain additional documentation from IBR manufacturers, and submit that data to the Planning Coordinator, Transmission Planner, Transmission Operator, Reliability Coordinator and Compliance Enforcement Authority. A minimum of three years should be allowed.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	

Answer	Yes
Document Name	
Comment	
Enel North America agrees with comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
yes, Legacy inverters will not be able to ride through voltage and frequency events. It's important to include exemption for legacy inverters. Kimberly Turco on behalf of Constellation Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Legacy inverters will not be able to ride through voltage and frequency events. It's important to include exemption for legacy inverters. Alison Mackellar on behalf of Constellation Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	

Dane Rogers - Dane Rogers On Behalf of: Donald Hargrove, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 5, 6; - Dane Rogers, Group Name OG&E	
Answer	Yes
Document Name	
Comment	
OG&E Supports comments submitted by MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS supports the following comments that were submitted by EEI on behalf of their members: EEI appreciates the revisions to PRC-029-1 and generally agrees that the changes align with many aspects of the discussions held during the NERC Technical Ride-through Conference. However, we are concerned that Requirement R4 overlooks the impacts to GOs who are developing large, multi-year IBR projects that may not be completed by the effective date of this Reliability Standard. Resource equipment specifications are typically locked down at the time the recourse contracts are finalized, and a change in requirements/specifications after that point can require changes in the design of the equipment that are impossible to achieve without triggering a material modification, resulting interconnection restudies and delaying or potentially canceling the project. To address this concern, we suggest the following modifications be made to Requirement R4 (in boldface below). **R4.** Each Generator Owner identifying an IBR that is in-service or has a contract for an IBR that is in effect by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting Ride- through criteria as detailed in Requirements R1-R3, and requires an exemption from specific Ride-through criteria shall:*10* *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	

AES Clean Energy agrees that the major changes have been accurately represented. Some concerns on changes that have not been included are listed below.

Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
MRO NSRF appreciates the work that the SC and SDT put in to drafting this standard and feel that much of what was covered at the technical conference was represented in the most recent draft, however we feel that there were some issues brought up during the conference which may have been overlooked and are addressed in question 2.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power (MP) supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	

See EEI comments	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
PG&E recommends the DT to consider development of a Implementation Guide and/or a Compliance Monitoring and Enforcement Program (CMEP) Practice Guide. Of particular benefit would be including examples of what would demonstrate compliance with Requirement R2.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
see EEI comments	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 1

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	Yes
Document Name	

Comment

See comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	

Comment

The PRC-024-4 and PRC-029-1 Implementation Plan should be amended to reflect both voltage and frequency Ride-through requirements as modified in PRC-029-1. This oversight should be made consistent with the revised standard. Accordingly, the following sections should be modified to remedy this concern: (1) General Considerations and (2) Equipment Limitations and Process for Requirement R4.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	Yes
Document Name	

Comment

MH appreciates the work that the SC and SDT put in to drafting PRC-029-1 and generally agrees that the changes align with aspects of the discussions held during the NERC Technical Ride-through Conference.	
Likes 0	
Dislikes 0	
Response	
Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
While two key important items from the Technical Conference were incorporated in the latest draft of the standard (hardware limitation exemptions for existing resources for frequency requirements; and aligned the frequency ride-through requirements with the IEEE 2800 standard), there were two additional key items from the Technical Conference that have not been captured in the latest draft of the standard: 1) Requirement R4 should be updated to allow hardware equipment limitations for any IBRs that already have a signed interconnection agreement (IA) as of the effective date of the standard. Given that equipment purchases/decisions and IBR plant designs are already locked down at the time the IA is signed, this will cause significant issues for these IBRs to meet the new requirements of PRC-029 if they were not designed that way. Reference comments submitted by SEIA and Orsted that explain this concern at greater length. 2) Further clarification of the evidence requirements for R4 hardware limitations. While the M4 measures were updated to add the damage curves from OEMs as possible evidence, during the Technical Conference the industry discussed that R4 evidence for PRC-029 should ultimately be aligned with the evidence requirements as detailed in the PRC-024 standard. Aligning the PRC-029 evidnece to the same as PRC-024 will support clarifty and efficiency of implementation/evidence gather of the standard by the industry.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	
Document Name	
Comment	
Eversource supports the comments of EEI.	
Likes 0	
Dislikes 0	

Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	

Document Name	
Comment	

NV Energy appreciates the revisions to PRC-029-1 and generally agrees that changes align with many aspects of the discussions held during the NERC Technical Ride-through Conference. However, we are concerned that Requirement R4 overlooks the impacts to GOs who are developing large, multi-year IBR projects that may not be completed by the effective date of this Reliability Standard. Resource equipment specifications are typically locked down at the time the interconnection agreement is signed, and a change in requirements/specifications after that point can require changes in the design of the equipment that are impossible to achieve without triggering a material modification, resulting interconnection restudies and delaying or potentially canceling the project. To address this concern, we suggest the following modifications be made to Requirement R4 (in boldface below).

R4. Each Generator Owner identifying an IBR that is in-service **or has signed a Large Generator Interconnection Agreement** by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting Ride- through criteria as detailed in Requirements R1-R3, and requires an exemption from specific Ride-through criteria shall:*10* *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

EEI appreciates the revisions to PRC-029-1 and generally agrees that the changes align with many aspects of the discussions held during the NERC Technical Ride-through Conference. However, we are concerned that Requirement R4 overlooks the impacts to GOs who are developing large, multi-year IBR projects that may not be completed by the effective date of this Reliability Standard. Resource equipment specifications are typically locked down at the time the recourse contracts are finalized, and a change in requirements/specifications after that point can require changes in the design of the equipment that are impossible to achieve without triggering a material modification, resulting interconnection restudies and delaying or potentially canceling the project. To address this concern, we suggest the following modifications be made to Requirement R4 (in boldface below).

R4. Each Generator Owner identifying an IBR that is in-service **or has a contract for an IBR that is in effect** by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting Ride- through criteria as detailed in Requirements R1-R3, and requires an exemption from specific Ride-through criteria shall:*10* *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

Likes 0	
Dislikes 0	
Response	
Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	

Comment

The work and efforts of this standard drafting team are much appreciated. Thank you for considering EPRI comments on the previous drafts as submitted previously. The new Draft 4 appears to be improved based on discussions that took place at the Standards Committee and NERC Ride-through Technical Conference on September 4-5, 2024. However, further improvements and alignment could be considered as follows:

A. General comments:

- Aligned with the directives to NERC in FERC order 901, the draft PRC-029 standard and the Implementation Plan for Project 2020-02 propose that the requirements apply to all applicable IBRs upon the standard's revised effective date or the newly added phased-in compliance dates. Applicable IBRs include existing (Legacy) IBRs that are already in operation prior to the specified dates. Requirement R4 provides a path for each Generator Owner to request a limited and documented exemption of a legacy IBR from the voltage ride-through criteria specified in R1 and R2 and frequency ride-through criteria specified in R3. According to the Implementation Plan of Project 2020-02, "[o]ther NERC Standards Development projects will be pursued to address ongoing identification and mitigation of any potential reliability impacts to the BPS for such exemptions."
    - The proposed approach may require documentation of hardware limitations or reconfiguration for a significant number of legacy IBRs across North America. Neither the draft Technical Rationale nor the FERC record under RM22-12 present or cite sufficient technical evidence that supports this broad application of the proposed standard to existing IBRs in all applicable NERC regions.
    - International experience has shown that documentation of hardware limitations to support exemption from, or the retroactive application of similarly stringent ride-through capability requirements on legacy IBRs are associated with significant uncertainties, potential technical and procedural challenges, and costs. Justification of similarly ambitious regulations enforced in other countries required the production of evidence like post-mortem disturbance analysis or case studies that *quantified* the potential impact of non-compliant existing IBRs on the bulk power system stability and reliability.[1],[2]
    - Consequently, stakeholder concerns contribute to low approval rates for the draft PRC-029, possibly causing delays in moving the draft standard through the NERC process toward timely and effective enforcement for at least all new IBRs. Considering the approx. 2,600 GW of new IBRs in the interconnection queues across North America[3], these delays bear potentially significant risk for the BPS.
    - Furthermore, the proposed revised effective date and newly added phased-in compliance date of the capability-based elements of Requirements R1, R2, and R3 as specified in the draft PRC-029 are different from the transition periods found in international practice of similarly ambitious rule changes for new and legacy IBRs (see the comments on Implementation Plan below for further details).
- The term Inverter-based Resource (IBR) to which the draft standard is intended to apply refers to proposed definitions being developed under the Project 2020-06 Verifications of Models and Data for Generators. Although the new draft includes redlines that strike the explicit mentioning of VSC-HVDC transmission facilities that are dedicated connections for IBR to the BPS, the definition proposed by Project 2020-06 is sufficiently broad that it could cover such facilities. For further clarity on the scope and application of the proposed PRC-029 standard, it could be helpful to add a clarifying sentence or to copy parts of Footnote 2 that clarifies the location of the "main power transformer" in case of IBR connecting via a dedicated VSC-HVDC transmission facility into the terms section on page 2 of the standard.
- For the purpose of clarity, harmonization, and compliance of IBR across North America, proposed requirements could even further align with requirements that are testable and verifiable as specified in voluntary industry standards developed through an open process such as ANSI, CIGRE, IEC, or IEEE. The drafting team is encouraged to review these standards and where applicable further align, for example:
    - Requirement R1 and R2 relate to IEEE Std 2800™-2022, Clause 7.2.2 (Voltage disturbance ride-through requirements), with consideration of Clause 7.3.2.4 (Voltage phase angle changes ride-through) as a stated exception in R1.
    - Requirement R3 relates to IEEE Std 2800™-2022, Clause 7.3.2 (Frequency disturbance ride-through requirements), with consideration of Clause 7.3.2.3.5 (Rate of change of frequency (ROCOF) ride-through) as a stated exception in R3.
    - Measures M1–M3 relate to IEEE P2800.2 Draft 1.0a, Clause 5 (Type tests), Clause 6 (Validation procedures for IBR unit models and supplemental IBR device models), and Clause 7 (Design evaluations), Clause 8 (As-built installation evaluations), Clause 9 (Commissioning tests), Clause 10 (Post commission model validation), and Clause 11 (Post-commissioning monitoring).
    - Measure M4, additionally, relates to IEEE P2800.2 Draft 1.0a, Clause 12 (Periodic tests), and Clause 13 (Periodic verification).
- The draft standard does not specify grid conditions for which the specified ride-through requirements apply. During its lifetime, a plant may experience many different operational conditions, along with changes to the grid, and may fail to ride-through an event if the plant was operating in a grid condition vastly different from that which it was designed for. The standard could include an exception for such situations based on leading industry practices, or a requirement for the TP, PC, etc. to specify such an exception.

- IEEE 2800-2022 allows for an exception for “self-protection” when negative-sequence voltage is greater than specified duration and threshold within continuous operation region. There is no such exception in draft PRC-029. Such an exception may be necessary for type III wind turbine generator (WTG) based plants.
- Standard does not allow any flexibility for failure of ride-through resulting from misoperation of protection system. The misoperation of protection system may occur for many reasons over the life of a plant. For example, for a fault on a transmission system, if differential protection for the main step-up transformer misoperates due to environmental issues such as damage due to water from a leaking roof or animal intrusion, then plant would be considered out of compliance. If a synchronous machine based generating plant trips because of similar issue, it would not be out of compliance with PRC-024.
- Requirements R1–R4 call out both “design and operation”. If the plant is designed to ride-through, then is it necessary to specifically call out and include IBR “operation” into the scope of PRC-029?
    - The inclusion of “operation” in PRC-029 would put a Generator Owner out of compliance with the standard whenever one of their IBR plants fails to ride-through real world disturbances, including incidents where failure of ride-through within the specified abnormal voltage and frequency conditions was beyond the GO’s control.
    - An alternative approach could be to narrow the scope of PRC-029 to require a Generator Owner to adequately *design* each IBR *to have the capability* to ride-through the specified abnormal conditions. The GO could then be further required by PRC-028 and PRC-030 to monitor IBR performance during operations and for real world events. If an IBR was found to have failed ride-through during operations, then PRC-030 could require the GO to identify the underlying issues and to take corrective action.

B. Ride-through definition

· Consider adopting definition from IEEE 2800, which is from IEEE 1547, and well understood by the industry. This was supported by about 68% of the respondents to the Slido poll during the NERC Technical Conference.

C. Requirement R1:

- Requirement calls out “design and operation”. If the plant is designed to ride-through then is it necessary to specifically call out “operation”?
    - The Reliability Standard PRC-006, Requirement R3, requires PC to develop UFLS program. Several assumptions are made here. If an event occurs, then R11 requires assessment of an event and if deficiency in UFLS program is identified then PC is required to consider deficiencies in R12. If UFLS program was deficient then PC is not out of compliance with R3 (or any other requirements in the standard). This is a good-faith approach: Design UFLS program and if actual event shows deficiency in UFLS Program then fix it. No compliance issues, as far as UFLS program was designed per Requirement R3.
    - Same approach could be taken in PRC-029, where R1 could require that plant is designed to ride-through specified voltage disturbance. The PRC-028 and PRC-030 then requires monitoring of plant performance and take corrective actions when necessary.
    - The same approach could be extended to requirements R2 and R3.
- If IBR operation remains within the scope of PRC-029, then consider revising the beginning of the sentence as following for better readability: *Each Generator Owner shall design and operate each IBR to meet or exceed Ride-through requirements…*
    - The same changes could be extended to requirements R2 and R3.

D. Requirement R2

- Refer to comments on R1 that could be extended to requirement R2.

E. Requirement R2, Part 2.1

- Why is it necessary to specify a performance requirement when voltage is in the continuous operation region? The standard remains silent on performance expectation for frequency ride-through requirements. For performance requirement for voltage ride-through mandatory operation region is also very brief. The intent of this standard is to focus on ride-through during voltage and frequency disturbances. If there is a desire to address performance then one option could be to simply state that performance shall be as specified by TP, PC, etc. That is in Part 2.1.3 anyway.

- Part 2.1.2: remove “and according to its controller settings”. It is not incorrect but “according to its controller settings” inherently apply to all performance requirements.
- Part 2.1.3: this requirement in IEEE 2800 was necessary and was tied to reactive power capability requirement as shown in Figure 8 of IEEE 2800. Given PRC-029 does not include reactive power capability requirements, perhaps PRC-029 could remain silent.

F. Requirement R2, Part 2.2

- Part 2.2 applies at the high-side of the main power transformer. The IBR is required to exchange current, up to the maximum capability. How is the “maximum capability” of an IBR determined? There could be some explanation, perhaps with examples, in the technical rationale document.
- The phrase “provide voltage support on affected phases during both symmetrical and unsymmetrical voltage disturbances” is confusing.
    - It is understood that intent is to require to inject “unbalanced current” or “negative-sequence” current during asymmetrical faults. However, as written, injection of balanced reactive current into an unbalanced fault meets the requirement to provide voltage support on affected phases, in addition to unaffected phase. The standard does not prohibit voltage support on unaffected phases. The voltage support on unaffected phase is usually problematic. But the requirement, as written, does not prohibit this.
    - During a L-G fault, current in a faulted phase is dependent on transformer winding configuration. Does this requirement, unintentionally, specify specific transformer configuration?
- During mandatory operation, voltage is abnormal and could be almost zero for close-in faults. As such, “current” over “power” is more appropriate. Power in faulted and unfaulted phases could be different as well. Replace real and reactive power with active (real) and reactive current respectively.

G. Requirement R2, Part 2.3.1

- Per language in attachment 1, permissive operation is allowed when line-to-ground or line-to-line voltage is below 10%. But per Part 2.3.1, IBR is required to restart current exchange when positive-sequence voltage enters continuous or mandatory operation region. This is conflicting. For example, for a line-to-ground fault on high-side terminals of main power transformer, the positive-sequence voltage would be more than 10%, i.e., in the mandatory operation region.

H. Requirement R2, Part 2.4

- The intent of this requirement is understood. However, if there are multiple plants in the area, then one plant misbehaving may cause overvoltage on high-side terminals of the main power transformer of other plants in the area. Also, the post-fault dynamics greatly depend on system operating condition (peak, shoulder, off-peak, etc.) along with transmission outages, status of capacitor banks, etc. The Generator Owner usually does not have system data to evaluate post-fault system dynamics and to determine if plant’s behavior is or not a contributing factor to overvoltage.

I. Requirement R3

- Refer to comments on R1 that could be extended to requirement R3.
- Footnote 9 could be simplified as following: *The ROCOF is an average rate of change of frequency over an averaging window of at least 0.1 second.*

J. Requirement R4

- We re-iterate the following observations related to the Effective Date and Phased-in Compliance Dates stated in the Implementation Plan of the project, as previously offered in our EPRI comments on the initial draft of PRC-029:

o Aligned with the directives to NERC in FERC order 901, the draft proposes that all requirements specified in PRC-029 apply to all applicable IBRs upon the standard's effective date, including Legacy IBRs that were already in operation prior to that date. This approach may require reconfiguration or documentation of hardware limitations for a significant number of existing IBRs across North America. In some cases, for example where the original equipment manufacturer (OEM) of hardware used in Legacy IBRs has gone out of business, or the OEM has ceased to support a legacy hardware product line, documentation of hardware limitations and development of models accurately representing Legacy IBR performance may be challenging. Additional exemptions to address these challenges could be included in R4 of the draft standard or the implementation plan.

o One example for an alternative approach to the one proposed in the draft PRC-029 could be that TOs and reliability coordinators were to discern on a regional or case-by-case basis about the application of PRC-029 to Legacy IBRs, preferably based on technical evidence like case studies assessing and quantifying the potential BPS reliability impacts from Legacy IBR in their regions.[4] If documentation of Legacy IBR hardware limitations was not available, worst-case assumptions could be made in these case studies. If such studies indicated a viable reliability risk, R4 could be applied to selected or all Legacy IBRs. This could produce documentation of hardware limitations to refine study assumptions to produce more realistic case study results. If refined results still indicated a viable reliability risk, R1-R3 could be applied to Legacy IBRs selectively.

- For further comments on the Effective Date and Phased-in Compliance Dates refer to below comments on the Implementation Plan.
- Parts 4.1 and 4.2 refers to exemption for a plant but part 4.3 refers to hardware in plant. If few of many wind-turbine generators in a plant are replaced, then plant still has limitation because most of the wind-turbine generators still have limited capability. Perhaps some clarification could be added that if "all hardware with documented capability limitation" is replaced, only then an exemption for a legacy IBR would not apply any longer.

K. Violation Risk Factors

- The language for the assignment of a VRF to Requirement R4 in the draft standard is truncated. Consider revising to: *[Violation Risk Factor: Lower]*
- Each Generator Owner is required per Requirement R4 to identify, document, and communicate about legacy IBRs that have hardware limitations related to the voltage ride-through criteria specified in R1 and R2. Why is a VRF of "Lower" assigned to R4 and not a VRF of "Medium"? Could the uncertainty related to the capability and performance of legacy IBRs associated with a violation of R4 (a requirement that is administrative in nature and a requirement in a planning time frame) by a Generator Owner not, under the abnormal conditions, be expected to directly and adversely affect the electrical state or capability of the Bulk-Power System, or the ability to effectively control the Bulk Power System?

L. Violation Severity Levels

- R1, R2, and R3: The lower VSL for each of these requirements is for failure to demonstrate the design capability to ride-through. There are two reasons for which this could arise:

(1) Plant is capable to ride-through but is not demonstrated in design evaluation or interconnection studies.

(2) Plant is not capable to ride-through and that is demonstrated in design evaluation or interconnection studies.

- Reason (1) is not a problem for grid reliability, it is just that studies are not adequate to demonstrate ride-through capability, and hence lower VSL is justified. But reason (2) is not any different from a case in severe VSL where an entity fails to demonstrate that IBR adhered to ride-through requirements (based on actual system disturbance event data).
- The VSLs could be rephrased to read:
    - Lower VSL: *The Generator Owner failed to produce adequate evidence demonstrating for each applicable IBR that it was designed to Ride-through in accordance with …*

- Severe VSL: *The Generator Owner either produced evidence demonstrating for any of their applicable IBR that it was not adequately designed to adhere to Ride-through, or the Generator Owner failed to produce evidence of actual disturbance monitoring data for a specific event that demonstrate each applicable IBR adhered to Ride-through requirements in accordance with …*

M. Attachment 1

- Tables 1 and 2 are inconsistent. Table 1 states ">= 1.10" whereas Table 2 states ">1.10".
- Clarify that cumulative window, for voltage band where ride-through duration is 1800-second, is 3600-second. Also, consider clarifying that 1800-second ride-through duration is only applicable to nominal voltages other than 500 kV.
- Numbered item #3: states that applicable voltage is "… on the AC side of the transformer(s) that is (are) used to connect…..". Both sides of transformer are AC, one is on DC-AC converter side and another on AC grid side. As written, voltage on either side of transformer is applicable. Please clarify that applicable voltage is on AC "grid" side of the transformer.
- Numbered item #5: Consider revising as following - *The applicable voltage for Tables 1 and 2 is identified as the voltage max/min of phase-to-[strike: neutral] [add: ground] or phase-to-phase fundamental [add: frequency] root mean square (RMS) voltage at the high-side of the main power transformer.*
- Numbered item #7: The interpretation of ride-through curves/points needs further clarification. Would a wind-based IBR plant be required to ride-through an event where at t=0 voltage drops from nominal to zero, then @t=0.16 s voltage rises to 25%, @t=1.2 s voltage rises to 50%, @t=2.5 s voltage rises to 70%, @t=3 s voltage rises to 90%? The item (8) is also tied to item (12), where a combined "area" is stated. Does must ride-through zone represent an "area" (represented by deviation in voltage multiplied by time duration)? Consider adding a few examples in the technical rationale.
  - Note that IEEE 2800-2022, informative Annex D, Section D.1 (Interpretation of voltage ride-through capability requirements specifies) states that the interpretation used in the standard is a "voltage versus time curve." However, the same Annex includes a Figure D.4 that intends to show "a realistic and complex trajectory of a voltage during a disturbance" for which the informative annex then further states that an IBR plant "is required to ride through," effectively interpreting the IEEE 2800-2022 ride-through curves as a "voltage versus time envelope." Thus, there seems to be some ambiguity in IEEE 2800-2022 as to how to interpret its ride-through curves, a finding that could be considered and resolved in a potential future revision or amendment of IEEE 2800.
  - If the voltage ride-through requirements proposed in Attachment 1 were to be specified or interpreted as a "voltage versus time envelope,", and considering that an unknown number of IEEE SA balloters that voted affirmatively on IEEE 2800-2022 may have interpreted the IEEE 2800-2022 requirements as the less stringent "voltage versus time curves" explained in Annex D of the standard, the proposed PRC-029 could be perceived as more stringent than IEEE 2800-2022.
  - Adding a few examples in the technical rationale could help clarify the correct interpretation of the voltage ride-through curves specified in Attachment 1.
- Numbered item 10: Please clarify if this statement applies to protection applied to high side of main power transformer only OR everywhere in the plant. An alternative could be to state that voltage protection of any type applied within the IBR shall not limit IBR from meeting the Ride-through requirements specified in this standard.

N. Attachment 2:

- Consider adding a statement that frequency ride-through requirements apply only when voltage is in the must ride-through zone.
- Numbered item 3: What is meant by control settings? Is the intent to state protection settings instead?

O. Implementation Plan

- The proposed effective date and phased-in compliance date of the capability-based elements of Requirements R1, R2, and R3 as specified in PRC-029-1 *for primarily new IBRs* of,

- “the first day of the first calendar quarter that is *twelve months [emphasis added by EPRI]* after” either “the effective date of the applicable governmental authority’s order approving” or “the date the standard is adopted by the NERC Board of Trustees” for (primarily new) Bulk Electric System IBRs, and
- “until the later of: (1) January 1, 2027; or (2) the effective date of the standard” for (primarily new) Applicable Non-BES IBRs

are different from transition periods found in international practice of similarly significant rule changes for new IBRs. Examples for reference include, but are not limited to:

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  - (European) Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators, Article 72 (Entry into force) states, “the requirements of this Regulation shall apply from *three years [emphasis added by EPRI]* after publication.” [5]
  - German Government, “Verordnung zu Systemdienstleistungen durch Windenergieanlagen (Systemdienstleistungsverordnung – SDLWindV) (Ordinance for Ancillary Services of Wind Power Plants (Ancillary Services Ordinance - SDLWindV),”[6]

- Mandatory requirement for new wind power plants to meet specified requirements by March 31, 2011, i.e., *19 months* after ordinance entered into force.

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  - ERCOT, “Issue NOGRR245. Inverter-Based Resource (IBR) Ride-Through Requirements. Report of Board Meeting on June 18, 2024,”[7] and ERCOT, “Nodal Operating Guide Revision Request (NOGRR) 245, Inverter-Based Resource (IBR) Ride-Through Requirements. ERCOT Update,” August 8, 2024.”[8]

- All new IBRs with a Standard Generation Interconnection Agreement (SGIA) after August 1, 2024, i.e., *immediately once the NOGRR enters into force* (subject to change until ERCOT board approval and until there is a non-appealable Public Utility Commission of Texas (PUCT) final order is in place)

- Extension of exemption from requirements new IBRs with a Standard Generation Interconnection Agreement (SGIA) after August 1, 2024, does not exceed December 31, 2028, i.e., *4 years and 4 months* (subject to change until ERCOT board approval and until there is a non-appealable Public Utility Commission of Texas (PUCT) final order is in place)

- The proposed effective date and phased-in compliance date of the Requirement R4 as specified in PRC-029-1 *for primarily legacy IBRs* of,
  - “the first day of the first calendar quarter that is *twelve months [emphasis added by EPRI]* after” either “the effective date of the applicable governmental authority’s order approving” or “the date the standard is adopted by the NERC Board of Trustees” for (primarily legacy) Bulk Electric System IBRs, and
  - “until the later of: (1) January 1, 2027; or (2) the effective date of the standard” for (primarily legacy) Applicable Non-BES IBRs

are either not applicable, or—for re-configurations that do not require replacement of hardware—comparable—they are different from transition periods found in national and international practice of similarly significant retro-active enforcements for legacy IBRs. Examples for reference include, but are not limited to:

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  - (European) Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators, Article 4 (Application to existing power-generating modules) states, [9]

- “Existing power-generating modules are not subject to the requirements of this Regulation, except where: … .”

- “For the purposes of this Regulation, a power-generating module shall be considered existing if:

· (a) it is already connected to the network on the date of entry into force of this Regulation; or

· (b) the power-generating facility owner has concluded a final and binding contract for the purchase of the main generating plant by *two years [emphasis added by EPRI]* after the entry into force of the Regulation.

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    - German Government, “Verordnung zu Systemdienstleistungen durch Windenergieanlagen (Systemdienstleistungsverordnung – SDLWindV) (Ordinance for Ancillary Services of Wind Power Plants (Ancillary Services Ordinance – SDLWindV)),”[10]

\- Financial incentive for voluntary retrofits of legacy wind power plants between July 11, 2009, and January 1, 2011, i.e., *1.5-years*.

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    - German Government, “Verordnung zur Gewährleistung der technischen Sicherheit und Systemstabilität des Elektrizitätsversorgungsnetzes (Systemstabilitätsverordnung - SysStabV) (System Stability Regulation – SysStabV)),“[11]

\- Mandatory requirement for reconfiguration of legacy IBRs and distributed energy resources (DERs) larger than 100 kW by August 31, 2013, i.e., *13 months* after ordinance entered into force.

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    - ERCOT, “Issue NOGRR245. Inverter-Based Resource (IBR) Ride-Through Requirements. Report of Board Meeting on June 18, 2024,”[12] and ERCOT, “Nodal Operating Guide Revision Request (NOGRR) 245, Inverter-Based Resource (IBR) Ride-Through Requirements. ERCOT Update,” August 8, 2024.”[13]

\- Mandatory requirement for legacy IBRs with an SGIA executed prior to August 1, 2024 to maximize the performance of their protection systems, controls, and other plant equipment (within equipment limitations) to achieve, as close as reasonably possible, the capability and performance set forth in IEEE 2800-2022 no later than December 31, 2025, i.e., *17 months* after NOGRR enters into force.

\- Extension of exemption from requirements for legacy IBRs with a Standard Generation Interconnection Agreement (SGIA) prior to August 1, 2024, does not exceed December 31, 2027, i.e., *3 years and 4 months* (subject to change until ERCOT board approval and until there is a non-appealable Public Utility Commission of Texas (PUCT) final order is in place)

- Per the Implementation Plan, IBR plants under construction now and entering commercial operation after the effective date of this standard are required to fully comply with this standard. Such plants are not allowed an exemption as permitted by Requirement R4. Prior to FERC Order 2023, the development and design-freeze for IBR plants does not occur until months or years after an interconnection agreement is signed. Large IBR plants, especially wind plants, could need a few years for construction, testing, trail operation, etc., before entering commercial operation. The equipment for plants under construction currently may have been purchased a year or two before the construction began and typically soon after signing an interconnection agreement. Consider revising Requirement R4 to allow hardware limitation exemptions for IBRs that have signed interconnection agreements, and not just IBRs that are in-service, as of the effective date of the standard.
- The first use of the word “or” in the sentence under the section Effective Date and Phased-in Compliance Dates, PRC-029-1 Phased-in Compliance Dates, Requirement 4, Applicable Non-BES IBRs on page 5 of the Implementation Plan could be replaced for clarity with the word “for” to then read: *Entities shall not be required to comply with Requirement R4 for their non-BES IBRs until the later of: (1) January 1, 2027; or (2) the effective date of the standard.*

P. Technical Rationale

- IEEE Std 2800™-2022, a voluntary industry standard for *Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems* is mentioned in the Technical Rationale document for PRC-029-1 but not cited properly. In all instances where the document refers to that IEEE standard, referencing could be improved by following our guidance offered below. Where appropriate, reference to and proper citation of IEEE P2800.2, an active IEEE Standards Association project for developing of a *Recommended Practice for Test and Verification Procedures for Inverter-based Resources (IBRs) Interconnecting with Bulk Power Systems*, may serve as an additional reference.
    - Suggested referencing of IEEE Std 2800™-2022:

- For the initial citation within any document, we suggest citing the standard as follows: IEEE Std 2800™, IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems

- Subsequent mentions of the standard could refer to it as: IEEE 2800

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  - Similar guidelines could be applied to IEEE Std 2800.2™:

- We recommend citing the standard in full on first reference as: IEEE P2800.2, Draft Recommended Practice for Test and Verification Procedures for Inverter-based Resources (IBRs) Interconnecting with Bulk Power Systems

- Followed by subsequent mentions as: IEEE P2800.2

- Considering the explicit statements in the "PRC-029-1_Technical_Rationale" document about the intended alignment with IEEE Std 2800™-2022 requirements in formulating the technical content of PRC-029-1 by the drafting team, references to specific clauses of IEEE Std 2800™-2022 could provide more clarity to industry stakeholders about which parts of the IEEE standard the PRC-029-1 aims to incorporate. It may also be helpful to identify areas where they are not aligned. Refer to the examples in our general comments above.
- IEEE 2800-2022 may not be the only industry standard with scope that overlaps with the proposed PRC-029 standard. ANSI and CIGRE currently may not have related standards. While IEC does have standards and technical specifications with related scope, these documents tend to be less specific in their technical requirements compared to IEEE standards like IEEE 2800-2022.[14]

Q. Justifications

- The table for “VRF Justifications for PRC-029-1, Requirement R3” on page 11 of the Justifications lists a Proposed VRF of “Lower”; but the draft PRC-029 standard assigns R3 a “[Violation Risk Factor: High]”. Consider resolving inconsistency across the two documents.
- Refer further to the comment on the VRF assignment for Requirement R4 above.

[1] Grid Codes for Interconnection of Inverter-Based Distributed Energy Resources by Country: Recent Trends and Developments. EPRI. Palo Alto, CA: November 2014. 3002003283. [Online] https://www.epri.com/research/products/000000003002003283 (last accessed, January 24, 2023)

[2] Dispersed Generation Impact on CE Region Security: Dynamic Study. 2014 Report Update. European Network of Transmission System Operators for Electricity (ENTSO-E), ENTSO-E SPD Report, Brussels, Belgium: December 2014. [Online] https://eepublicdownloads.entsoe.eu/clean-documents/Publications/SOC/Continental_Europe/141113_Dispersed_Generation_Impact_on_Continental_Europe_Region_Security.pdf (last accessed, January 24, 2023)

[3] LBNL (2024) [Online] https://emp.lbl.gov/generation-storage-and-hybrid-capacity

[4] EPRI is currently working on case studies relevant to these topics and is also aware of others doing similar work.

[5] ENTSO-E: Requirements for Generators. [Online] https://www.entsoe.eu/network_codes/rfg/ (last accessed, August 6, 2024)

[6] Federal Law Gazette I (no. 39) (2009): 1734–46. [Online] https://www.clearingstelle-eeg-kwkg.de/gesetz/695 (last accessed, August 6, 2024)

[7] ERCOT, “Issue NOGRR245. [Online] https://www.ercot.com/mktrules/issues/NOGRR245 (last accessed, August 9, 2024)

[8] ERCOT, “Nodal Operating Guide Revision Request (NOGRR) 245, Inverter-Based Resource (IBR) Ride-Through Requirements. ERCOT Update,” August 8, 2024 [Online] https://www.ercot.com/calendar/08082024-NOGRR245-_-Review-of (last accessed, August 9, 2024)

[9] Ref. Footnote 10

[10] Federal Law Gazette I (no. 39) (2009): 1734–46. [Online] https://www.clearingstelle-eeg-kwkg.de/gesetz/695 (last accessed, August 6, 2024)

[11] Federal Law Gazette I (no. 40) (2012): 1635. [Online] https://www.gesetze-im-internet.de/sysstabv/BJNR163510012.html (last accessed, August 6, 2024)

[12] Ref. Footnote 16

[13] Ref. Footnote 17

[14] Example IEC standards and technical specifications with related scope may include IEC 61400-27, IEC 62934:2021, IEC TS 63102:2021, and IEC TR 63401-4:2022.

Likes 0	
Dislikes 0	

Response

2. Provide any additional comments for consideration, if desired.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT generally supports incorporating as much of the IEEE 2800-2022 language and parameters into PRC-029-1 as possible, and commends NERC's and the Standards Committee's use of material drawn from IEEE 2800-2022. Consistent with the approach taken in IEEE 2800-2022, ERCOT encourages any future revisions to PRC-029-1 and its attachments that clarify that entities are not precluded from exceeding the minimum requirements of any ride-through curves and performance measures if their equipment is capable of doing so. Much progress has been made, however ERCOT is voting against this draft of PRC-029-1 due to the substantive issues raised in these comments and previous comments that have not been addressed. Nonetheless, ERCOT recognizes and appreciates NERC's, the Standards Committee's, and the Project 2020-02 drafting team's extraordinary level of effort in developing these critically needed ride-through performance requirements.

As an initial matter, the ride-through definition proposed in draft 4 of PRC-029-1 continues to only require a facility to remain connected and continue "to operate," which is inadequate; the definition needs to require the facility to maintain performance beneficial (or, at the very least, not detrimental) to overall grid reliability. The Standards Committee's response to previous comments on this topic stated that the definition cannot specify exact performance. ERCOT's comment was not intended to suggest that performance requirements be stated in the definition. Rather, ERCOT believes the definition of ride-through needs to include qualifications on what it means to operate in the context of ride-through, just as the existing defined term "Reliable Operation" places qualifications on what it means to reliably operate elements of the Bulk-Power System. ERCOT believes that similar qualifications are necessary in the context of ride-through because ERCOT has encountered arguments that IBRs that performed poorly during events where ride-through was needed were operational despite their poor response and poor performance simply because at least part of the plant did not trip during the event.

Similarly, the concept of ride-through also ought to recognize that the continued operation associated with ride-through must be maintained not only through the Disturbance but all the way through recovery to a new operating point. The existing Disturbance definition does not clearly include the recovery period.

In addition, ERCOT believes that partial trips are inconsistent with the concept of ride-through, not simply performance parameters to be addressed solely under PRC-030. The requirement to ride through should apply to both the IBR facility and the individual IBR units (inverters and turbines), and ERCOT is concerned that the removal of "in its entirety" from the ride-through definition in draft 4 of PRC-029-1 reduces the effectiveness of the definition. While the requirements in draft 4 of PRC-029-1 provide some indication that partial tripping is not permissible, specifying that ride-through includes individual inverters and turbines will provide clarity in PRC-029-1 and consistency if the definition is used in other places in the Standards. Most—if not all—IBR ride-through events observed in the ERCOT Region include some level of partial IBR tripping (i.e., some percentage of inverters/turbines tripping while the overall plant remains connected).

To address these concerns, ERCOT recommends the ride-through definition be revised as follows:

Definition Proposed in Draft 4 of PRC-029-1:

Ride-through: The plant/facility remains connected and continues to operate through voltage or frequency system disturbances.

ERCOT's Proposed Definition:

Ride-through: The entire plant/facility (including individual inverters and turbines) remains connected and injects current to the Bulk Power System and continues operating to support grid reliability through a System Disturbance, including the period of recovery to a normal operating condition.

Requirement R1 does not clarify whether partial trips (individual IBR unit trips) would be allowed. ERCOT believes Requirement R1 should not allow individual turbine/inverter trips and should clearly indicate "ride-through" does not occur when individual turbines or inverters trip offline during a Disturbance. Requirement R2 provides some level of clarity that partial tripping is not allowed if it would result in more than 10% loss of real power for voltage ride-through requirements, and revising Requirement R1 to indicate that ride-through precludes individual turbine/inverter trips would be consistent with Requirement R2.

ERCOT recommends replacing the term "adheres" in Requirement R2 with "meets or exceeds," which is used in Requirement R1, to clarify that protection and control settings can be configured to exceed the minimum requirements when the equipment in question is capable of better performance. This would be consistent with recommendations NERC has made through multiple channels for many years.

ERCOT also recommends reviewing and revising Requirement R2, Part 2.1 and the surrounding language to clarify the facility should continue to deliver the pre-disturbance level of current, as appropriate, because power depends on voltage. In principle, during a Disturbance, active power should only reduce proportionally to voltage such that active current is consistent unless needed for frequency response. Reactive current should adjust as needed to support voltage (lead or lag, as appropriate) up to its current limits. In general, the Requirement should neither incentivize entities to undersize inverters/converters nor impose onerous requirements to oversize the equipment. This lack of clarity may cause issues in enforcing this requirement and miss the reliability objective. Using "current" where appropriate also aligns with paragraph 209 of FERC Order 901.

In addition, requiring a facility to deliver reactive power "according to its controller settings" is impractical and misses the objective. The requirement should be designed to *ensure the proper response performance,* as each facility will always, by definition, "operate according to its controller settings," even if those settings happen to be incorrect. To make Requirement R2, Part 2.1 truly be a performance-based requirement, it should be revised to require generators to meet or exceed performance requirements instead of simply requiring them to operate according to their settings.

PRC-029-1 Requirement R2, Part 2.2, should not simply specify reactive/active power priority because not all priority implementations perform the same way. As proposed, Part 2.2 does not prohibit dropping active current to zero even for shallow voltage dips (e.g. 0.7-0.9 per unit), but seems to allow the Transmission Planner (TP), Planning Coordinator (PC), Reliability Coordinator (RC), or Transmission Operator (TOP) to specify the desired performance. ERCOT requests that Part 2.2 be revised as necessary to clarify that excessive or full momentary cessation of active current is not allowed or to specify the circumstances under which it is allowed (e.g., extremely low voltage deviations).

ERCOT also recommends that the Implementation Plan be revised to clarify what constitutes being "in operation" (unit synchronization, full commercial operations, or some other milestone) for purposes of determining whether an IBR may be considered for a potential exemption under the Implementation Plan.

ERCOT encourages NERC to consider defining the averaging window for Rate of Change of Frequency (RoCoF) because leaving the averaging window open-ended will result in measurement inconsistencies in protection systems and post-event analysis. Defining the averaging window will also ensure that the 5 Hz/second RoCoF proposed in Requirement R3 of draft 4 of PRC-029-1 is sufficient. For example, using the Odessa 2022 event as a benchmark, the minimum averaging window of IEEE 2800-2022 of 0.1 seconds yields a RoCoF between 5 – 12 Hz/second at some stations, suggesting 5 Hz/second is not sufficient and the Reliability Standard should contain a higher requirement as allowed by IEEE 2800-2022. However, if a longer averaging window—such as 0.5 seconds—is used, observed RoCoF for the Odessa 2022 event would have been under 5 Hz/second and the RoCoF requirement proposed in draft 4 of PRC-029-1 would suffice. Having a sufficient averaging window can also prevent transient measurements during the normal fault and fault clearing times from causing erroneous trips.

NERC should ensure the proposed 5 Hz/second RoCoF requirement does not conflict with footnote 3 in cases where the IBR does not monitor RoCoF in its protection settings, but its PLL controls are not properly set to ride-through.

ERCOT, as an RC, PC, and TOP, generally opposes PRC-029-1's broad approach of allowing hardware exemptions without some level of confirmation of the exemption's impact (such as an evaluation of the reliability impact of the exemption by a PC, RC, TP, or TOP). ERCOT believes reliability specifically requires that limitations be modeled and provided to the PC/RC/TP/TOP. Accurate modeling is important enough to be explicitly referenced in the Standard and should be required if a limitation is to be allowed/confirmed. There are a growing number of presentations and communications from generation owners regarding current models not reflecting all limitations. Reliability entities should not be required to accept models that do not reflect actual or expected performance. Instead, the Reliability Standard should require models (both positive sequence and EMT models) to be improved to include all limitations (e.g., inverter DC protections). Otherwise, the PC/RC/TP/TOP will be unable to model all of a facility's limitations and will incorrectly conclude that the facility demonstrates acceptable performance when, in fact, the IBR will not ride through. Reliability entities may not be able to assess a limitation that is merely described without also being modeled, which may limit their ability to perform determination studies, resulting in a gap that reliability entities must address. This places the burden on the PC/RC/TP/TOP instead of on Generator Owners (GOs), who should be responsible for removing the limitation or improving the model fidelity. Consequently, ERCOT believes the proposed approach in draft 4 of PRC-029-1 misses the objective of FERC's directive that the RC/PC/TP/TOP should ensure that reliability is maintained while any allowed exemptions are in effect. Additionally, ERCOT believes PRC-029-1 should incentivize facility owners to explore the availability of less expensive upgrades (including hardware upgrade kits) that can remove limitations rather than allowing them to pass the burden of unmodeled limitations onto reliability entities that do not have the means to secure the system against limitations they cannot properly model. ERCOT has received information from some OEMs that some less costly upgrades (e.g., communication speed capabilities, control card updates, etc.) are available that could efficiently and cost-effectively address some limitations.

ERCOT is also concerned that the language added to Requirement R4 that allows GOs to withhold information from PCs, TPs, TOPs, and RCs if the original equipment manufacturer considers the information to be proprietary could significantly hamper efforts by these reliability-focused functional entities to accurately assess the impact of an exemption under Requirement R4. As detailed in the preceding paragraph, properly understanding the impact of an exemption is essential to reliable system operations, and it is unclear what reliability purpose is served by allowing GOs to withhold information from PCs, TPs, TOPs, and RCs, especially when GOs are still required to provide that information to the Compliance Enforcement Authority (CEA). Furthermore, it is unclear what non-reliability purpose such withholding serves. PCs, TPs, TOPs, and RCs are not commercial competitors of IBR original equipment manufacturers, and, like the CEA, these functional entities routinely and necessarily handle confidential, commercially sensitive information in the course of their day-to-day operations and are no strangers to the systems and practices necessary to manage such information.

Additionally, ERCOT is concerned that the word "replaced" in PRC-029-1 Requirement R4, Part 4.3.1 may provide a pathway to circumvent the spirit of the Standard, as it does not clearly specify whether an exemption expires when equipment is refurbished, and an argument could be made that the refurbished equipment was not "replaced." ERCOT believes that an existing exemption should no longer be needed after the underlying equipment is refurbished, and recommends using "replaced, refurbished, or updated" in Requirement R4 to clarify this point.

In the course of the development process for ERCOT's ride-through requirements, some entities indicated that some software and firmware upgrades may also require memory upgrades and sought clarity as to whether such memory upgrades would be considered "hardware" upgrades. In response, ERCOT clarified that such upgrades would be considered part of the underlying software and firmware upgrades, and ERCOT encourages NERC to include this same clarification in PRC-029-1.

Likes 0	
Dislikes 0	

Response

Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	2020-02_EPRI Comments on Draft 4 of NERC PRC-029 (IBR ride-through) Reliability Standard.pdf

Comment

I. Introduction

1. The Electric Power Research Institute (EPRI)[1] respectfully submits these comments (This Response) in response to North American Electric Reliability Corporation (NERC)'s request for formal comment on Project 2020-02 Modifications to PRC-024 (Generator Ride-through), issued on September 24, 2024.

2. EPRI closely collaborates with its members inclusive of electric power utilities, Independent System Operators (ISOs), and Regional Transmission Organizations (RTOs), as well as numerous other stakeholders, domestically and internationally. In its role, EPRI conducts independent research and development relating to the generation, delivery, and use of electricity for public benefit by working to help make electricity more reliable, affordable and environmentally safe. EPRI's comments on this topic are technical in nature based upon EPRI's research, development, and demonstration experience over the last 50 years in planning, analyzing, and developing technologies for electric power.

3. EPRI research and technology transfer deliverables are generally accessible on its website to the public, either for free or for purchase, and occasionally subject to licensing, export control, and other requirements.[2] The publicly available and free-of-charge milestone reports from a U.S. Department of Energy (DOE)- and EPRI member-funded research project, Adaptive Protection and Validated Models to Enable Deployment of High Penetrations of Solar PV ("PV-MOD"), [3] and other research deliverables substantiate many of the comments made in This Response.

4. While not a standards development organization (SDO), EPRI conducts research and demonstration projects in relevant areas as well as facilitates knowledge transfer and collaboration that SDOs may, at times, use to inform technical and regulatory standards development, such as in Institute of Electrical and Electronics Engineers (IEEE), International Electrotechnical Commission (IEC), International Council on Large Electric Systems (CIGRE), and NERC.[4]

5. EPRI's comments in This Response address reliability and NERC's draft PRC-029 Reliability Standards for IBRs ride-through requirements developed under project 2020-02. All comments are aimed at providing independent technical information to respond to the draft published by NERC based on EPRI's research and development results and associated staff expertise and do not necessarily reflect the opinions of those supporting and working with EPRI to conduct collaborative research and development. Where appropriate, EPRI's comments do not only address the specific questions of the NOPR but also related scope that may help to inform a final order. Some of EPRI's comments presented in This Response have also been submitted in response to the previous Federal Energy Regulatory Commission's (FERC) Notice of Proposed Rulemaking (NOPR) to direct North American Electric Reliability Corporation (NERC) to develop Reliability Standards for inverter-based resources (IBRs) that cover data sharing, model validation, planning and operational studies, and performance requirements (RM22-12), issued on November 17, 2022.

6. EPRI also submitted comments on the initial draft of PRC-029 which was issued on March 27, 2024, on Draft 2 which was issued June 18, 2024, and on Draft 3 which was issued on July 22, 2024. This 4th set of EPRI comments supports the same direction as the previously submitted comments and offers a technical analysis based on the latest "Draft 4".[5]

II. Conclusion

7. EPRI appreciates the opportunity to provide NERC with its technical recommendations and comments on these important topics related to Reliability Standards for IBRs. EPRI looks forward to working with its members, NERC, and other stakeholders on providing further independent technical information on these important questions.

III. Contact Information

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[1] EPRI is a nonprofit corporation organized under the laws of the District of Columbia Nonprofit Corporation Act and recognized as a tax-exempt organization under Section 501(c)(3) of the U.S. Internal Revenue Code of 1996, as amended, and acts in furtherance of its public benefit mission.

EPRI was established in 1972 and has principal offices and laboratories located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass. EPRI conducts research and development relating to the generation, delivery, and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety, and the environment. EPRI also provides technology, policy and economic analyses to inform long-range research and development planning, as well as supports research in emerging technologies.

[2] https://www.epri.com (last accessed, August 6, 2024)

[3] PV-MOD Project Website. EPRI. Palo Alto, CA: 2024. [Online] https://www.epri.com/pvmod (last accessed, August 6, 2024)

[4] For transparency, we would like to disclose that EPRI collaborates with other organizations such as IEEE, IEC, CIGRE, and NERC; however, EPRI is not a regulatory- or standard-setting organization. EPRI research is often considered in the development of recommendations, guidelines, and best practices that are not determinative.

[5] https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx

Likes 0	
Dislikes 0	

Response

Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC

Answer	
Document Name	

Comment

- The exemptions are only for equipment that is in-service by the effective date of PRC-029-1. The concern remains that facilities under construction at the effective date might not meet the requirements. The time needed to perform studies of the ongoing projects would be limited. Without an exemption for new equipment, we may be at risk of having to sacrifice protection to meet requirements of the standard.

If an exemption is used, the standard requires “Identification of the specific piece(s) of hardware causing the limitation” and “Technical documentation verifying the limitation is due to hardware that would need to be physically replaced to meet all Ride-through criteria”. Our existing limitation memo from one of our suppliers is vague. We are not sure how successful we would be in obtaining the required detailed information. Further, the standard requires that we “Provide a copy of the acceptance of a hardware limitation by the CEA…”. I think this means we would need the Compliance Enforcement Authority to accept our statement that there is a hardware limitation, likely making a vague response from a manufacturer unacceptable.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	
Document Name	

Comment

OPG supports NPCC Regional Standards Committee's comments.

Likes 0	
Dislikes 0	

Response

Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

Elevate appreciates the opportunity to comment on the draft NERC standards, particularly those pertaining to future IBR NERC Reliability Standards, and FERC Order No. 901 directives. Elevate also appreciates the revisions in the latest draft of PRC-029-01 that include the hardware limitation exemptions for frequency ride-through requirements for existing resources, and the alignment of the frequency ride-through requirements in Attachment 2 with the IEEE 2800 standard that properly balances the capabilities of IBRs today with grid reliability.

Elevate continues to strongly encourage NERC to reconsider adoption of IEEE 2800-2022. The unwillingness to adopt IEEE 2800-2022 by NERC is leading to entirely duplicative efforts that are not serving any additional value as compared to the work conducted in the IEEE 2800-2022 developments. It does not appear that a holistic approach and strategy is being taken to meet the FERC Order No. 901 directives, which is leading to very low ballot scores, significant rework, and misalignment with industry recommended practices.

The draft NERC PRC-029 is duplicative with IEEE 2800-2022 Clause 7 yet only covers a small fraction of the IBR-specific capability and performance requirements and necessary equipment limitation details that are outlined in that clause. Therefore, there is no clear reliability benefit versus the cost of implementation PRC-029 as compared with IEEE 2800-2022 and the recommendations set forth in the NERC disturbance reports and guidelines.

Concerns with Draft PRC-029

If the draft PRC-029 standard is to be pursued as currently structured, Elevate would like to highlight the following concerns listed below. These should be addressed in a future version of the standard.

· **Inconsistencies with PRC-029 and IEEE 2800-2022:** There are numerous inconsistencies in the draft standard language and attachment 1 and 2 when compared to IEEE 2800-2022. These should be considered and reviewed for clarity and completeness in the standard.

o IEEE 2800 identifies the following items, but the standard does not support. Clarification/review should occur for each of these items:

*IEEE 2800 recognizes limitations with VSC-HVDC equipment in meeting consecutive votlage deviation ride-through capabilite, the PRC-029 standard does not.

*IEEE 2800 allows for an exception for "self-protection" when negative-sequence voltage is greater than specified duration and threshold. This may be required for Type III WTG based plants, and this exception does not exist in PRC-029

*IEEE 2800 recognizes 500kV system voltages are actually operated in the range of 525kV and therefore has equipment rated to 550kV. These 500kV operating conditions and corresponding updated voltage ride-through curves should be considered in the standard.

*IEEE 2800 allows for an exception for "self-protection" when negative-sequence voltage is greater than specified duration and threshold. This may be required for Type III WTG based plants, and this exception does not exist in PRC-029

*IEEE 2800 7.2.2.1 has an exception on IBR post-disturbance current limitations for voltage disturbances that reduce RPA voltage to less than 50% of nominal. PRC-029 does not have this exception.

*For V > 1.05 and ≤ 1.10, a ride-through duration of 1800 seconds is specified in both IEEE 2800 and draft PRC-029. The IEEE 2800-2022 specifies that this ride-through duration is cumulative over a 3600 second time period. Draft PRC-029 remains silent regarding applicable cumulative time-period.

*The standard should be updated to explicitly state that the voltage ride-through curves are to be interpreted as voltage vs time duration as is stated in IEEE 2800. This is to ensure that there is no incorrect interpretation that these curves are “envelope” curves. This could be done by adding a new note to explicitly call out the voltage vs time duration interpretation of the curves.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	
Document Name	

Comment

Attachment 1 to PRC-029-1 is a set of performance-based criteria for voltage ride-through. Footnote 10 to Tables 1 and 2 in Attachment 1 is a design consideration that does not belong in a set of performance requirements. It should be removed.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	
Document Name	

Comment

(1) The wording in Section 2.1.3 is unclear. MH recommends it be changed to “Prioritize Real Power or Reactive Power **delivery** when the voltage is less than 0.95 per unit, the voltage is within the continuous operating region, and the IBR cannot deliver both Real Power and Reactive Power due to a current limit or Reactive Power limit unless otherwise specified through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.”

(2) Facilities section 4.2.1. The Elements associated with (1) Bulk Electric System (BES) IBRs. What is the IBR aggregate nameplate capacity rating (greater than or equal to 20 MVA or 75MVA)? The IBR aggregate nameplate capacity rating need to be added to 4.2.1.

Likes 0	
Dislikes 0	

Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Nick Leathers - Ameren - Ameren Services - 1,3,5,6 - MRO,SERC	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	

Comment

NIPSCO supports the following additional comments provided by the NAGF:

a. Revise the language to include exemptions for software limits and balance of plant issues. Alternatively, clarify that a hardware limitation includes software and balance of plant equipment limitations.
b. Requirement R4 and R4.1– current draft language only applies to IBRs that are in service before the effective date of PRC-029-1. Need to consider revising to address IBRs that will be in-service 2-3 years from now and are currently in design/procurement that potentially will not be able to meet PRC-029-1 requirements. Recommend that the R4.1 12-month exemption documentation reporting criteria be extended to 36 months to address this issue.
c. Requirement R4.2.2 – the NAGF is unclear as to what the Compliance Enforcement Authority (CEA) acceptance for an IBR hardware limitation exemption will consist of. Will the CEA provide an email response confirming acceptance to the Generator Owner submitting the exemption? How are such exemptions to be submitted and to whom within the CEA organization? The CEA process needs to be defined, otherwise this requirement is not enforceable.
d. Requirement R4.3 could be interpreted such that any Ride-through capability limiting component that is replaced with a like and kind component to fully meet R1-R3 is without the ability to obtain exemption from Ride-through criteria (i.e. the exemption no longer applies). This could force the retirement of IBRs which are in-service prior to the effective date of PRC-029-1 and that have hardware failures for which a replacement component that fully meets all Ride-through criteria is not available. The NAGF provides the following revised language for consideration:
4.3.1 When existing hardware causing the limitation(s) is replaced with hardware that changes the Ride-through capability of the IBR, the exemption for that Ride-through criteria no longer applies.
4.3.1.1 If the limitations requiring exemption from R1-R3 are still present, documentation must be updated and resubmitted as required.
The proposed modifications ensure that it is clearly understood that a Generator Owner can use like-in-kind replacements for hardware components that may fail on IBRs which are in-service prior to the effective date of PRC-029-1.

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	
Document Name	

Comment

See comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 2	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI is concerned that the language in R3 exceeds what a GO can provide. GO's do not design their resources. They develop specifications for procurement and operate those resources within their design capabilities, as specified by the OEM. In the case of legacy resources, they have not been designed to meet the requirements contained in PRC-029 or IEEE 2800-2020. Therefore, they cannot ensure, even if they conduct an EMT analysis of that resource that it will in all cases operate in a manner that meets or exceeds these standards. To address this concern, we ask that the language in R3 be changed to better align with what GOs can meet. To address our concern, we offer the following (in boldface): **R3.** Each Generator Owner shall **provide documentation** that each IBR **is configured to** meet or exceed Ride-through requirements during a frequency excursion event whereby the System frequency remains within the "must Ride-through zone" according to Attachment 2 and the absolute rate of change of frequency (RoCoF) magnitude is less than or equal to 5 Hz/second, unless a documented hardware limitation exists in accordance with Requirement R4. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	
Document Name	
Comment	

PacifiCorp supports EEI and MRO NSRF comments on this Standard.	
Likes 0	
Dislikes 0	
Response	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
see EEI comments	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
see EEI comments	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	
Document Name	
Comment	
NRG is in support of the additional comments for consideration provided by NAGF regarding the PRC_029 draft 4.	

Likes 0	
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	
Document Name	

Comment

NRG Provides the following comments that mirror those of the NAGF.

a. *Revise the language to include exemptions for software limits and balance of plant issues. Alternatively, clarify that a hardware limitation includes software and balance of plant equipment limitations.*

b. *Requirement R4 and R4.1– current draft language only applies to IBRs that are in service before the effective date of PRC-029-1. Need to consider revising to address IBRs that will be in-service 2-3 years from now and are currently in design/procurement that potentially will not be able to meet PRC-029-1 requirements. Recommend that the R4.1 12-month exemption documentation reporting criteria be extended to 36 months to address this issue.*

c. *Requirement R4.2.2 – NRG is unclear as to what the Compliance Enforcement Authority (CEA) acceptance for an IBR hardware limitation exemption will consist of. Will the CEA provide an email response confirming acceptance to the Generator Owner submitting the exemption? How are such exemptions to be submitted and to whom within the CEA organization? The CEA process needs to be defined, otherwise this requirement is not enforceable.*

d. *Requirement R4.3 could be interpreted such that any Ride-through capability limiting component that is replaced with a like and kind component to fully meet R1-R3 is without the ability to obtain exemption from Ride-through criteria (i.e. the exemption no longer applies). This could force the retirement of IBRs which are in-service prior to the effective date of PRC-029-1 and that have hardware failures for which a replacement component that fully meets all Ride-through criteria is not available. NRG agrees with the proposed NAGF revised language for consideration:*

4.3.1 When existing hardware causing the limitation(s) is replaced with hardware that changes the Ride-through capability of the IBR, the exemption for that Ride-through criteria no longer applies.

4.3.1.1 If the limitations requiring exemption from R1-R3 are still present, documentation must be updated and resubmitted as required.

The proposed modifications ensure that it is clearly understood that a Generator Owner can use like-in-kind replacements for hardware components that may fail on IBRs which are in-service prior to the effective date of PRC-029-1.

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See EEI comments	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
NV Energy is concerned that the language in R3 exceeds what a GO can provide. GO's do not design their resources. They develop specifications for procurement and operate those resources within their design capabilities, as specified by the OEM. In the case of legacy resources, they have not been designed to meet the requirements contained in PRC-029 or IEEE 2800-2020. Therefore, they cannot ensure, even if they conduct an EMT analysis of that resource that it will in all cases operate in a manner that meets or exceeds these standards. To address this concern, we ask that the language in R3 be changed to better align with what GOs can meet. To address our concern, we offer the following (in boldface): **R3.** Each Generator Owner shall **provide documentation ensure the design and operation is such** that each IBR **is configured to** meet**s** or exceed**s** Ride-through requirements during a frequency excursion event whereby the System frequency remains within the "must Ride-through zone" according to Attachment 2 and the absolute rate of change of frequency (RoCoF) magnitude is less than or equal to 5 Hz/second, unless a documented hardware limitation exists in accordance with Requirement R4. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*	
Likes 0	
Dislikes 0	
Response	

Brian Lindsey - Entergy - 1	
Answer	
Document Name	
Comment	

It is unclear why the CEA needs to be included in the notification of limitations. What is the CEA's role, other than a reviewer/approver and why the does the CEA need to approve or accept these limitations. Without a defined process it is unclear how this requirement can be enforced.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	
Document Name	

Comment

Sections 4.1 and 4.2 call for documenting hardware limitations and reporting the same within 12 months following the effective date of PRC-029-1. As the equipment manufacturer panelists stated, they will have to evaluate each site individually. Given the number of legacy units in service and the number of units that will connect to the grid before the effective date of the standard, evaluating all the data and providing necessary attestations within a 12 month period is not practical. The equipment manufacturer panelists also stated that resources will be an issue. More time is needed to document all this.

WEC Energy Group suggests that the SDT create and add graphs to support Tables 1 and 2 and the respective notes. Graphs should highlight "must Ride-through zone" and "may Ride-through zone" terms that are listed in note 11. One of the early revisions had a graph. Why was it removed?

WEC Energy Group requests that an Implementation Guidance document be created and published to help industry better understand this convoluted and unclear standard and how to implement it.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment

MP supports the MRO NSRF comments regarding Requirement 4.3. MP also supports EEI's comments regarding Requirement 3

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	

The NAGF provides the following comments for consideration:

a. Revise the language to include exemptions for software limits and balance of plant issues. Alternatively, clarify that a hardware limitation includes software and balance of plant equipment limitations.

b. Requirement R4 and R4.1– current draft language only applies to IBRs that are in service before the effective date of PRC-029-1. Need to consider revising to address IBRs that will be in-service 2-3 years from now and are currently in design/procurement that potentially will not be able to meet PRC-029-1 requirements. Recommend that the R4.1 12-month exemption documentation reporting criteria be extended to 36 months to address this issue.

c. *Requirement R4.2.2 – the NAGF is unclear as to what the Compliance Enforcement Authority (CEA) acceptance for an IBR hardware limitation exemption will consist of. Will the CEA provide an email response confirming acceptance to the Generator Owner submitting the exemption? How are such exemptions to be submitted and to whom within the CEA organization? The CEA process needs to be defined, otherwise this requirement is not enforceable.*

d. Requirement R4.3 could be interpreted such that any Ride-through capability limiting component that is replaced with a like and kind component to fully meet R1-R3 is without the ability to obtain exemption from Ride-through criteria (i.e. the exemption no longer applies). This could force the retirement of IBRs which are in-service prior to the effective date of PRC-029-1 and that have hardware failures for which a replacement component that fully meets all Ride-through criteria is not available. The NAGF provides the following revised language for consideration:

4.3.1 When existing hardware causing the limitation(s) is replaced with hardware that changes the Ride-through capability of the IBR, the exemption for that Ride-through criteria no longer applies.

4.3.1.1 If the limitations requiring exemption from R1-R3 are still present, documentation must be updated and resubmitted as required.

The proposed modifications ensure that it is clearly understood that a Generator Owner can use like-in-kind replacements for hardware components that may fail on IBRs which are in-service prior to the effective date of PRC-029-1.

Likes 0	
Dislikes 0	
Response	

Maozhong Gong - GE - GE Wind - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

Since the first wind turbine was installed in the U.S., product development across the industry has continued to evolve and advance. This evolution is a benefit for the industry because we have been able to install advanced technologies. However, this also means we have varying degrees of assets installed. For this reason, we strongly believe NERC needs to implement policies that recognize the distinctions between the operational fleet/assets and newly deployed units and establish different/distinct regulations for each. During the Technical Conference, several participants, including individuals participating in the pool process, highlighted the need for this distinguishment. It was suggested the applicability of PRC-024-3 ride-through requirements for installed assets, while applicability of PRC-029-1, aligned with IEEE 2800-2020, for newly deployed assets. While we understand NERC’s rationale to not “leave capability on the table”, there will be significant administrative challenges to apply for exemptions putting asset owners and OEMs at risk of not being able to fulfill the request. As stated by Arne Koerber, Executive for GE Vernova’s Wind Product Management, during the Technical Conference, proving that a capability is not possible is significantly more difficult than proving specific capability. A detailed system study for multiple product variants with multiple components configurations would be required to determine hardware limitations, which is unpractical and in certain cases unfeasible for older units. Some of the challenges with this effort could include: components’ vendors may no longer be in business and/or, lab setups or prototypes may no longer be in service.

There are other items that were discussed in the Technical Conference which we would like to highlight:

• IEEE 2800-2022 standard was not developed with the intent to impact existing assets, but with the intent to standardize requirements applicable tonew IBRs installations to support the grid of the future.

• Retroactive requirements diverge the focus of OEMs from developing new and modern products to fulfill the most challenging grid needs of the future.

• OEMs stated the need of ~5 years cycle to develop new products with the advanced capabilities stated. Yet, the implementation plan schedule hasn’t changed to allow the entire window suggested by FERC, which is by 2030.

We strongly recommend:

1. Proposing PRC-024-3 requirements to installed assets, while keeping PRC-029-1 aligned to IEEE 2800-2022 for new assets.

2. Developing an exemption process that is based on “product capabilities” and not focusing on “hardware limitations”. This will better demonstrate what the industry can do to comply with the provision.

3. Timing for compliance to be extended to the maximum allowed period given by FERC, which is by 2030.

Furthermore, we are concerned that policies are becoming too complex that the much-needed focus on zero emitting technologies are being put at risk. We included the number of GE Vernova assets impacted in two sections below; however, we strongly urge NERC to conduct a thorough analysis across the industry of all generation assets that would have to comply, including timing of compliance, units that may be unable to comply, and most importantly impact to the system if certain units cannot comply.

Proposed requirements for new installations:

Requirements which we are concerned for new installations after PRC-029 compliance date:

o **Multiple fault ride-through from Attachment 1, item 9**:

PRC-029-1 Draft 4 Proposal: While IEEE 2800-2022 allows IBRs to trip for more than two deviations for voltage levels below 0.25pu, PRC-029-1 requires more than 4 deviations for any voltage level. Also, IEEE 2800 allows wind turbines to trip on multiple faults to self-protect against mechanical resonance that exceed equipment limits.

GE Vernova’s ONW concerns: Riding-through multiple subsequent voltage excursions have significant mechanical and electrical stress on assets, specially at lower voltage levels (i.e. <0.25pu). It can significantly increase mechanical loads when multiple faults are spaced too close to the drive train frequency. Since the release and start of adoption of IEEE 2800-2022 requirements across North America, GE Vernova ONW is working on updating current products’ design to meet or exceed proposed requirements. As an OEM, consistent requirements allow us to plan and execute product development cycles efficiently and supports offering products with a wide applicability.

GE Vernova’s ONW recommendations: Align with IEEE 2800-2022, section 7.2.2.4, for consistency to IEEE 2800- 2022 efforts to harmonize requirements across North America.

o **Instantaneous trip settings from Attachment 1, item 10**:

PRC-029-1 Draft 4 Proposal: Instantaneous trip settings based on instantaneously calculated voltage measurements with less than filtering lengths of one cycle (16.6 millisecond) are not permissible.

GE Vernova's ONW concerns: The power electronics in individual inverter-based resources require sub-cycle overvoltage protection with fast filtering. It is infeasible to filter for a cycle to trip on extreme sub-cycle overvoltages that would cause equipment damage. The choice here is to protect generation by tripping followed by an auto-restart in a few minutes vs equipment damage followed by a trip (caused by equipment damage).

GE Vernova's ONW recommendations: Align with IEEE 2800-2022 which requires one cycle filtering for plant level disconnection and specify sub-cycle transient overvoltage requirements that IBRs have to ride through.

Proposed requirements for legacy installations:

Requirements which we are concerned for legacy installations prior PRC-029 compliance date:

o **Frequency ride-through from Attachment 2, Table 3:**

PRC-029-1 Draft Proposal: PRC-029-1 proposes frequency ride-through curve similar to IEEE 2800-2022, Section 7.3.2.1, retroactive for installed assets. GE Vernova's ONW concerns: While meeting this curve is not a concern for current products and legacy products since PRC-024-1 implementation, it is a concern however that a substantial number of turbines installed prior to 2014 do not fully meet the curve. These products represent over 20GW of units installed in North America. For type 3 wind turbines, grid frequency determines the synchronous speed which in turn determines the slip. Larger frequency deviations result in higher slip which results in higher voltages on the rotor side converter. Additionally auxiliary devices such as motors are impacted. Evaluation of potential design impact is ongoing; however, at this point GE Vernova's ONW cannot confirm whether such changes will impact hardware. These turbines meet or exceed the grid requirements that were in place at the time of installation.

GE Vernova's ONW recommendations: Apply PRC-024-3 requirements to installed assets. If frequency ride through capability of the product is higher than requirements, these assets are set to the maximum product capability. GE Vernova does not commission wind turbines to operate at the frequency ride-through requirement capability, but rather at the product capability, which meets or exceeds requirements that were enforced at the time assets were installed.

o **Voltage ride-through from Attachment 1, Table 1**:

PRC-029 proposal: PRC-029-1 proposes voltage ride-through curve similar to IEEE 2800-2022, Section 7.2.2.1.

GE Vernova's ONW concerns: For all installed GE Vernova ONW wind turbine variants with enabled Zero Voltage Ride-Through capability (ZVRT), voltage ride-through curve may potentially be met at POI due to the voltage drops across the wind plant collector system and the substation transformer, but only project specific evaluation can confirm it. Note that ZVRT is an available parametrization-only upgrade to GE Vernova's ONW legacy wind turbines. These products represent the entirety of the installed base in North America. Changes to the wind turbine voltage ride-through capability to meet the proposed curve, require the rotor to withstand additional mechanical loads during voltage excursions. Power path, critical auxiliary devices, rotor side converter and dynamic braking circuit might require re-design to handle energy dump from the generator. Evaluation of potential design impact is ongoing; however, at this point GE Vernova's ONW cannot confirm whether such changes will impact hardware. While a full assessment on a per product variant will take time, potential turbine modifications include replacement of auxiliaries (i.e. motors), changes to operating rotor RPM curves reducing turbine energy production, and full (in the case of the oldest turbines) or partial replacement of converters. These turbines meet or exceed the grid requirements that were in place at the time of installation.

GE Vernova's ONW Recommendations: Apply PRC-024-3 requirements to installed assets. GE Vernova offers ZVRT which helps legacy plants in meeting or exceeding voltage ride-through requirements of PRC-024-3.

o **Multiple fault ride-through from Attachment 1, item 9**:

PRC-029-1 Draft 4 proposal: While IEEE 2800-2022 allows IBR to trip for more than two deviations for voltage levels below 0.25pu, PRC-029-1 states more than 4 deviations for any voltage level. Also, IEEE 2800 allows wind turbines to trip on multiple faults to self-protect against mechanical resonance that exceed equipment limits.

GE Vernova's ONW concerns: Riding-through multiple subsequent voltage excursions have significant mechanical and electrical stress on assets, specially at lower voltage levels (i.e. <0.25pu). It can significantly increase mechanical loads when multiple faults are spaced too close to the drive train frequency, and in the worst case require significant upgrades to the mechanical drive train.

GE Vernova's ONW recommendations: We recommend turbines to be required to attempt to ride through multiple voltage events and not trip on number of subsequent voltage deviations alone but allowed to trip to protect the integrity of the mechanical system e.g. if using devices such as slip couplings.

o **Instantaneous trip settings from Attachment 1, item 10**:

PRC-029-1 Draft 4 Proposal: Instantaneous trip settings based on instantaneously calculated voltage measurements with less than filtering lengths of one cycle (16.6 millisecond) are not permissible.

GE Vernova's ONW concerns: The power electronics in individual inverter-based resources require sub-cycle overvoltage protection with fast filtering. It is infeasible to filter for a cycle to trip on extreme sub-cycle overvoltages that would cause equipment damage. The choice here is to protect generation by tripping followed by an auto-restart in a few minutes vs equipment damage followed by a trip (caused by equipment damage).

GE Vernova's ONW recommendations: Align with IEEE 2800-2022 which requires one cycle filtering for plant level disconnection and specify sub-cycle transient overvoltage requirements that IBRs have to ride through.

Likes 0	
Dislikes 0	

Response

John Pearson - ISO New England, Inc. - 2

Answer	
Document Name	

Comment

ISO New England supports the IBR requirements in this PRC-029-1 draft. R4 of this PRC-029-1 draft provides an exemption for IBRs in-service by the effective date of the standard that have hardware limitations that prevent them from meeting Ride-through criteria as detailed in Requirements R1-R3. ISO New England supports this exemption since the new requirements in PRC-029-1 were not applicable when developers procured and constructed such IBRs. ISO New England is concerned that this exemption is insufficient in scope. Specifically, R4 will become effective before projects that, at this time, have a) completed the required interconnection studies according to applicable standards at that time, and b) have procured equipment and are under construction, but c) will not yet be in-service at the time the standard becomes effective within approximately the next three years. Permitting, procurement and construction often take years after a project completes its interconnection studies (where the project is studied to ensure reliability per the standards in effect at the time), especially considering today's development timelines and supply chain issues. Imposing new requirements at later development stages can cause delays and introduce compliance burdens that were not possible to anticipate during the project analysis and equipment procurement phases to planned projects that are well on their way to completing their interconnection.

Likes 0	
Dislikes 0	

Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	

It is the opinion of ACES that the language surrounding the applicability of the exemption criteria specified in Requirement R4 should be consistent in Requirements R1-R3. As written, both Requirements R2 and R3 contain the phrase "unless a documented hardware limitation exists in accordance with Requirement R4" whereas Requirement R1 only allows for an "accepted hardware limitation" for voltage at the "high-side of the main power transformer".

Furthermore, we believe that the phrase "and is initiated by a non-fault switching event on the transmission system" should be struck from the 3rd bullet point of Requirement R1. We contend that, as written, Requirement R1 requires the IBR to meet or exceed Ride-through requirements during a fault event for any value of the instantaneous positive sequence voltage phase angle while simultaneously allowing the IBR to trip (or initiate current blocking) during a non-fault switching event. It is our opinion that the GO will likely be unable to differentiate between an event initiated by a fault or an event initiated by a "non-fault switching event" on the Transmission system. In short, Transmission switching events are outside the purview of the GO.

We recommend the following language for Requirement R1.

R1. Each Generator Owner shall ensure the design and operation is such that each IBR meets or exceeds Ride-through requirements, in accordance with the "must Ride-through zone" as specified in Attachment 1, except in the following conditions: [Violation Risk Factor: High] [Time Horizon: Operations Assessment]

• Unless a documented hardware limitation exists in accordance with Requirement R4;

• The IBR needed to electrically disconnect in order to clear a fault;

• The instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer; or

• The Volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

We at ACES appreciate the work put forth by the SDT and the SC to listen and respond to Industry comments, particularly with respect to the exemption process. However, we continue to have concerns surrounding the language or Requirement R4, specifically part 4.3. It is our opinion that, as written, R4 part 4.3 does not allow for "like in kind" replacement of failed hardware. We recommend using the following language for Requirement R4 part 4.3:

4.3. Except as specified in Requirement R4, Part 4.3.2 below, each Generator Owner with a previously accepted limitation that replaces the hardware causing the limitation shall document and communicate such a hardware change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the hardware change.

4.3.1. Except as specified in Requirement R4, Part 4.3.2 below, when existing hardware causing the limitation is replaced, the exemption for that Ride-through criteria no longer applies.

4.3.2. Replacement hardware with the same capabilities and limitations of the existing hardware (commonly referred to as a "like-in-kind" replacement) shall be exempt from Requirement R4, Part 4.3.

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	
Document Name	

Comment

Black Hills Corporation agrees with what EEI has stated: "…EEI is concerned that the language in R3 exceeds what a GO can provide. GO's do not design their resources. They develop specifications for procurement and operate those resources within their design capabilities, as specified by the OEM. In the case of legacy resources, they have not been designed to meet the requirements contained in PRC-029 or IEEE 2800-2020. Therefore, they cannot ensure, even if they conduct an EMT analysis of that resource, that it will in all cases operate in a manner that meets or exceeds these standards."

Additionally, the NAGF in their additional comments made some great comments and modified change suggestions that Black Hills Corporation supports to help ensure clarity to this standard.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	2020-02_Unoffical_Comment_Form_09172024 - NSRF.docx

Comment

MRO NSRF would recommend the following modifications to Requirement 4.3.

4.3. Each Generator Owner with a previously accepted limitation that replaces the hardware causing the limitation shall document and communicate such a hardware change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the hardware change.

4.3.1 When existing hardware causing the limitation(s) is replaced with hardware that changes the Ride-through capability of the IBR, the exemption for that Ride-through criteria no longer applies.

4.3.1.1 If the limitations requiring exemption from R1-R3 are still present, documentation must be updated and resubmitted as required.

These modifications ensure that it is clearly understood that a Generator Owner can use like-in-kind replacements for hardware components that may fail on IBRs which are in-service prior to the effective date of PRC-029-1.

As currently written, R4.3 could be interpreted such that if any Ride-through capability limiting component is replaced, the IBR would be required to fully meet R1-R3 without the ability to obtain exemption from Ride-through criteria. This could force the retirement of IBRs which are in-service prior to the effective date of PRC-029-1 and that have hardware failures for which only like-in-kind replacements or replacement components that fully meets all Ride-through criteria are not available.

Additional MRO NSRF concerns include:

Frequency exemptions are currently limited to “hardware” only, MRO NSRF suggests that clarifying language be added to indicate that if “upgraded” software is not available the issue then then hardware exemption is acceptable.

Multiple manufacturers have indicated their inverters are capable, but they could not obtain specifications from supporting equipment manufacturers and that it would be extremely difficult to determine if the entire plant could ride through an excursion event and that facilities may trip due to ancillary equipment.

This issue with obtaining information for balance-of-plant equipment paired with the fact that all vendors at the NERC Technical conference agreed EMT studies would be required to verify facility level ride through capability leads to a great deal of concern regarding the ability to determine ride through capability for facilities in their entirety.

Additionally, the time required to develop EMT studies for the number of impacted facilities could be extremely challenging for GOs due to the limited resources available.

MRO NSRF is also concerned that the timeline for implementation could be extremely problematic if the effective date set forth by FERC is too soon. This could impact projects that are already under development and were not designed to IEEE 2800 requirements, providing many facilities that are coming online with no viable path to compliance.

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	
Document Name	

Comment

AES Clean Energy strongly supports the revisions that have been made and we greatly appreciate the efforts of the Standard Drafting Team and Standards Committee. Throughout the NERC Ride-through Technical Conference and in formal comments we raised concerns that R4 exemptions do not consider out of business OEMs and the possibility that limitations may not be hardware-based. AES Clean Energy offers the following suggestions to address these concerns:

1. Update the following language that has recently been added to the PRC-028 Technical Rationale and include in the PRC-029 Technical Rationale:

PRC-028 Technical Rationale Excerpt

“It is recognized that the manufacturer of an IBR unit in commercial operation before the effective date of this standard may be out of business, acquired by, or merged with another manufacturer. In such cases, if the entity is not able to determine capability of IBR unit to record the required SER data, the SER data is not required. Documentation should be retained to demonstrate that entity is unable to determine IBR unit recording capability from available manufacturer data either from an original manufacturer or from an acquiring manufacturer.”

Suggested PRC-029 Technical Rationale Addition

"It is recognized that the manufacturer of an IBR unit in commercial operation before the effective date of this standard may be out of business, acquired by, or merged with another manufacturer. In such cases, if the entity is not able to determine capability of IBR to meet Ride-through criteria as detailed in Requirements R1-R3, the IBR will be exempt from PRC-029. Documentation should be retained to demonstrate that entity is unable to determine IBR performance capability from available manufacturer data either from an original manufacturer or from an acquiring manufacturer."

2. Update the language in R4 to allow exemptions that are not hardware-based.

R4. Each Generator Owner identifying an IBR that is in-service by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1-R3, and requires an exemption from specific Ride-through criteria shall*:10 [Violation Risk Factor:Lower] [Time Horizon: Long-term Planning]*

4.1. Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1. This documentation shall include:

4.1.1 Identifying information of the IBR (name and facility number);

4.1.2 Which aspects of Ride-through requirements that the IBR would be unable to meet and the capability of the hardware IBR due to the limitation;

4.1.3 Identify the specific cause of piece(s) of hardware causing the limitation;

4.1.4 For hardware-based limitations, Ttechnical documentation verifying the limitation is due to hardware that would need to be physically replaced to meet all Ride-through criteria, and that the limitation cannot be removed by software updates or setting changes, and;

4.1.5 Information regarding any plans to remedy the hardware limitation (such as an estimated date).

3. Some consideration should be given that projects being placed in-service shortly after the Standard effective date will have been designed and procured several years prior and may require exemptions under R4. The first sentence of the requirement can be revised as follows:

"R4. Each Generator Owner identifying an IBR that reaches commercial operation is in-service before or within 24 months of by the effective date of PRC-029-1,…"

The following footnote from PRC-028 on commercial operation should be included for consistency:

"Commercial operation means achievement of this designation indicating that the facility has received all approvals necessary for operation after completion of initial start-up testing."

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	
Document Name	

Comment

AZPS supports the following comments that were submitted by EEI on behalf of their members:

EEI is concerned that the language in R3 exceeds what a GO can provide. GO's do not design their resources. They develop specifications for procurement and operate those resources within their design capabilities, as specified by the OEM. In the case of legacy resources, they have not been designed to meet the requirements contained in PRC-029 or IEEE 2800-2020. Therefore, they cannot ensure, even if they conduct an EMT analysis of that resource that it will in all cases operate in a manner that meets or exceeds these standards. To address this concern, we ask that the language in R3 be changed to better align with what GOs can meet. To address our concern, we offer the following (in boldface):

R3. Each Generator Owner shall provide documentation that each IBR is configured to meet or exceed Ride-through requirements during a frequency excursion event whereby the System frequency remains within the "must Ride-through zone" according to Attachment 2 and the absolute rate of change of frequency (RoCoF) magnitude is less than or equal to 5 Hz/second, unless a documented hardware limitation exists in accordance with Requirement R4. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1, Group Name Eversource

Answer	
Document Name	

Comment

Eversource supports the comments of EEI.

Likes 0	
Dislikes 0	

Response

Dane Rogers - Dane Rogers On Behalf of: Donald Hargrove, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 5, 6; - Dane Rogers, Group Name OG&E

Answer	
Document Name	

Comment

OG&E Supports comments submitted by MRO NSRF.

Likes 0	

Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	
Document Name	
Comment	

SMUD appreciates the actions taken by the Standard Drafting Team and the Steering Committee to revise the language in Section 4, Applicability so that it matches the Applicability language in PRC-028-1 and PRC-030-1. This was a minor but important change to ensure uniformity among this first set of IBR Standards.

SMUD is voting Affirmative on this draft #4 but believes that the term “in-service” in Requirement R4 is too vague and needs to be defined in either a future version of PRC-029, Implementation Guidance, or a CMEP Practice Guide. Entities who are planning, designing and constructing IBRs today with slightly older equipment could be caught in a Catch-22 if their project is delayed and the exemption from specific Ride-through criteria in Requirement R4 is dependent upon whether the project is “in-service” or not. The term in-service could be confused with the project’s energization date, commercial operation date, or other operational condition during construction and commissioning. For reference, Requirement R4 is listed here:

R4. Each Generator Owner identifying an IBR that is in-service [emphasis added] by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1-R3, and requires an exemption from specific Ride-through criteria shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	

1. The standard does not include exemption for instances when a transformer differential protection trip during a fault beyond our control. As written, IBR unit will be out of compliance.

2. The standard language in R4 mentions exception regarding hardware limitation but no mentions of software limitation. It should be added to avoid confusion.

3. Legacy sites may not be able to meet the new proposed FRT and VRT curves. Language in the standard needs to capture that and allow them to operate with max. capability without compliance repercussions.

4. Damage curve may not be an easy evidence document to get from OEM. It’s considered intellectual proprietary documentation.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment

1. The standard does not include exemption for instances when a transformer differential protection trip during a fault beyond our control. As written, IBR unit will be out of compliance.

2. The standard language in R4 mentions exception regarding hardware limitation but no mentions of software limitation. It should be added to avoid confusion.

3. Legacy sites may not be able to meet the new proposed FRT and VRT curves. Language in the standard needs to capture that and allow them to operate with max. capability without compliance repercussions.

4. Damage curve may not be an easy evidence document to get from OEM. It’s considered intellectual proprietary documentation.

Kimberly Turco on behalf of Constellation Segments 5 and 6.

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	
Document Name	

Comment

The Implementation Plan mandates compliance within 12 months of the effective date. This timeframe is insufficient to complete necessary studies, acquire additional documentation from IBR manufacturers if required, and submit the data to the Planning Coordinator, Transmission Planner, Transmission Operator, Reliability Coordinator, and Compliance Enforcement Authority (CEA).

Moreover, the standard does not clearly specify a procedure nor a timeframe for the CEA to accept or deny a hardware limitation. Consequently, 12 months is insufficient for both the GO to collect the data required in Requirement R4.1 and for the CEA to evaluate and determine acceptance or denial of any hardware limitations needing an exemption from specific Ride-through criteria.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	
Document Name	

Comment

Althought WECC voted affirmative, WECC suggests the following for clarity, and believes these are all non-substantive changes and would not require reposting. WECC suggests adding (IBR) after "Inverter-Based Resource" in the title or identifying IBR in the "Purpose" (or in Requirement R1). Part 4.2 should say “manufacturer” for OEM not “manufacture”. Requirement R4 Part 4.2.1 needs rewritten for clarity (remove “shall be provided”) The word "Provide" was added at the beginning. In Requirement R4 Part 4.3, the CEA will not know if the limitation has been mitigated as there is no obligation to inform the CEA yet the VSLs include the CEA (last of the “Or” statements for each level.) Should Table 2 for 1.10 pu be shown as ”≥ 1.10” (as in Table 1) and not simply “> 1.10”?

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	

Comment

FirstEnergy requests DT consider adding a range of return to pre-disturbance real power output. To satisfy R2.5 as written, IBR sites would need to operation in static VAR control rather than desired automatic voltage control (system actively adjusting VARs to control voltage). This would maintain a static power factor on the sties that would fail to provide effective voltage support due to manual intervention required to adjust VAR setpoint, not allowing for immediate response to voltage changes. This weakened response to voltage changes could result less stable grid voltage and increased potential for voltage trips, which does not align with the intent of the Standard. Changing this to provide a range from the pre-disturbance real power output would allow for change in setpoint for IBR operation during a transient such that this automatic voltage control could be utilized, improving voltage support from IBR generators and enhancing IBR stability and reliability.

In addition, the Standard uses the term “available power” in R2.5 for an acceptable return limit. This term is not defined and cannot be numerically determined at this time. FirstEnergy requests for DT to provide a definition for this term and a specific numerical methodology for determining “available power” at a solar site for given conditions.

Likes 0	
Dislikes 0	

Response

Jeffrey Streifling - NB Power Corporation - 1	
Answer	
Document Name	
Comment	
Attachment 1 to PRC-029-1 Draft 4 is a set of performance-based criteria for voltage ride-through. Footnote 10 to Tables 1 and 2 in said Attachment 1 is a design consideration that does not belong in the set of performance requirements. It should be removed.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
AEPC signed on to ACES comments, please see their commments.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	

Answer	
Document Name	

Comment

The exemptions are only for equipment that is in-service by the effective date of PRC-029-1. The concern remains that facilities under construction at the effective date might not meet the requirements. The time needed to perform studies of the ongoing projects would be limited. Without an exemption for new equipment, we may be at risk of having to sacrifice protection to meet requirements of the standard.

If an exemption is used, the standard requires "Identification of the specific piece(s) of hardware causing the limitation" and "Technical documentation verifying the limitation is due to hardware that would need to be physically replaced to meet all Ride-through criteria". Our existing limitation memo from one of our suppliers is vague. We are not sure how successful we would be in obtaining the required detailed information. Further, the standard requires that we "Provide a copy of the acceptance of a hardware limitation by the CEA…". I think this means we would need the Compliance Enforcement Authority to accept our statement that there is a hardware limitation, likely making a vague response from a manufacturer unacceptable.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	
Document Name	

Comment

While AEP appreciates the revisions to R4.2 which limits the sharing of material deemed proprietary by the manufacturer, the obligations (including footnote 11) nonetheless assume that the GO will still be able to obtain that material. If a manufacturer considers such information to be proprietary, it would be unlikely they would be willing to share it with the GO, even if the GO is obligated to obtain it in the standard. AEP recommends the removal of footnote 11 or that exclusions be included to accommodate situations where the manufacturer refuses to provide proprietary information to the GO.

AEP recommends removing the phrase "demonstrate the design of each IBR" from the proposed standard and returning to the original event-based requirements. The phrase may prove difficult to fully comply with, as a Functional Entity would have to know the design of the collector system and parameters and run the models correctly to demonstrate this. Much of this needed information would need to be provided by the manufacturer, which may require non-disclosure agreements.

If the design aspect is retained, then AEP offers the following: R1, R2 and R3 state, "Each Generator Owner shall ensure the design and operation is such…" Operation of the equipment is the GOP's responsibility, not the GO's. If the SDT's intention was regarding the design of the system, AEP recommends revising the language to instead state, "Each Generator Owner shall ensure the *operational design* is such…".

AEP is concerned by the inclusion of the phrase "through other mechanisms" in this standard, and recommend it be removed from Requirements 2.1.3, 2.2, and 2.5 as we believe it could be misinterpreted or misunderstood. It is not clear how the obligations are or are-not met when "through other mechanisms" is introduced. For example, if the TOP would need the GO to do "X" instead of "Y", and if the GO fails to do "X", has the GO failed to comply with the obligation or does this put the requirement *outside* of the standard? AEP instead recommends using the language from the Technical Rationale which references "or according to requirements specified."

AEP believes the text "Provide any response to additional information requested" in R 4.2.1 is confusing and should be clarified, as it is not clear what the intended meaning or purpose is of "any response." AEP suggests it instead state "Provide any additional information requested by the associated…".

There needs to be an exemption for system-related causes of ride-through failure. IBRs should be exempt from ride-through requirements in R1 through R3 if tripping or failure to ride through is attributable to any of the following:
1. Sub-synchronous control interaction or ferro-resonance involving series compensation confirmed by the TOP, RC, TP, or PC
2. Unstable behavior of other nearby IBRs or dynamic devices such as FACTS or HVDC confirmed by the TOP, RC, TP, or PC
3. System short circuit levels during contingencies below the level of IBR stable operation confirmed by the TOP, RC, TP, or PC
4. System-level transient or oscillatory instabilities confirmed by the TOP, RC, TP, or PC

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	
Document Name	

Comment

The exemptions are only for equipment that is in-service by the effective date of PRC-029-1. The concern remains that facilities under construction at the effective date might not meet the requirements. The time needed to perform studies of the ongoing projects would be limited. Without an exemption for new equipment, we may be at risk of having to sacrifice protection to meet requirements of the standard.

If an exemption is used, the standard requires "Identification of the specific piece(s) of hardware causing the limitation" and "Technical documentation verifying the limitation is due to hardware that would need to be physically replaced to meet all Ride-through criteria". Our existing limitation memo from one of our suppliers is vague. We are not sure how successful we would be in obtaining the required detailed information. Further, the standard requires that we "Provide a copy of the acceptance of a hardware limitation by the CEA…". I think this means we would need the Compliance Enforcement Authority to accept our statement that there is a hardware limitation, likely making a vague response from a manufacturer unacceptable.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

Revise Standard Section A. Introduction, 4. Applicability, 4.2 Facilities, 4.2.2, for the phrase "connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.". Most GO's do not have the ability to assess the "common point of connection". Either an action to ensure TO notifies GO of applicability or change to the "point of interconnect" is required.

Revise Technical Rationale to define the mechanism and associated parameters of an “event trigger” for the GO since it is not defined, and guidance is required. Revise Standard R4.2 to include a time limitation for the CEA to accept or reject a hardware limitation. Failure to define the time limitation leaves the GO subject to compliance risks and a possible noncompliance. Additionally, define process actions for a potential CEA denial, appeal process, etc. For Standard R4.1, define if month is “calendar” month, otherwise, define time-period for “Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1…”.

Likes 0	
Dislikes 0	

Response

Updated Reminder

Standards Announcement

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

Additional Ballot and Non-binding Poll Open through September 30, 2024

Now Available

An additional ballot for **PRC-029-1 - Frequency and Voltage Ride-through Requirements for Inverter-based Resources** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Monday, September 30, 2024**.

NOTE: This will be the last opportunity to vote on PRC-029-1. The proposed Standard will not be posted for final ballot.

The Standards Committee approved waivers to the Standard Processes Manual at their December 2023 meeting. These waivers were sought by NERC Standards staff for reduced formal comment and ballot periods. This will assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 901. FERC Order 901 was issued under Docket No. RM22-12-000 on October 19, 2023.

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here.

Note: Votes cast in previous ballots, will not carry over to additional ballots. It is the responsibility of the registered voter in the ballot pools to place votes again. To ensure a quorum is reached, if you do not want to vote affirmative or negative, cast an abstention.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Director of Standards Development, Jamie Calderon (via email) or at 404-960-0568. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2020-02 Modifications to PRC-024 (Generator Ride-through) observer list" in the Description Box.

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

Formal Comment Period Open through September 30, 2024

Now Available

A formal comment period for **PRC-029-1 - Frequency and Voltage Ride-through Requirements for Inverter-based Resources**, is open through **8 p.m. Eastern, Monday, September 30, 2024**.

On August 15, 2024, the NERC Board of Trustees (Board) invoked Section 321 of the NERC Rules of Procedure (ROP) to address critical and rapidly growing risk to the reliability of the Bulk Power System associated with inverter-based resources (IBR) in response to FERC Order No. 901 directives. PRC-029-1 (Frequency and Voltage Ride-through Requirements for Inverter-based Resources) is a draft standard designed to establish capability-based and performance-based Ride-through requirements for IBRs during grid disturbances. The draft standard failed to achieve consensus from the Registered Ballot Body over multiple ballots, calling into question whether development would be completed by FERC's filing deadline of November 4, 2024, which resulted in the Board acting under Section 321 of the ROP. Under this special authority, the Board directed the Standards Committee to work with NERC to host a technical conference and to ballot an additional ballot of PRC-029-1 within 45-days of the August 15 Board action.

The Standards Committee approved waivers to the Standard Processes Manual at their December 2023 meeting. These waivers were sought by NERC Standards staff for reduced formal comment and ballot periods. This will assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 901. FERC Order 901 was issued under Docket No. RM22-12-000 on October 19, 2023.

Note: PRC-024-4 passed the recent additional ballot (conducted June 28 – July 8, 2024). This standard will move to a final ballot when the PRC-029-1 ballots open (September 24-30, 2024) as only non-substantive revision(s) were made.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Additional ballots for the standard and implementation plan, as well as the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **September 24-30, 2024.**

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Director of Standards Development, Jamie Calderon (via email) or at 404-960-0568. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2020-02 Modifications to PRC-024 (Generator Ride-through) observer list” in the Description Box.

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/350)
Ballot Name: 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-029-1 AB 4 ST
Voting Start Date: 9/24/2024 12:01:00 AM
Voting End Date: 10/4/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 4
Total # Votes: 239
Total Ballot Pool: 267
Quorum: 89.51
Quorum Established Date: 10/4/2024 9:14:18 AM
Weighted Segment Value: 77.88

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	74	1	46	0.821	10	0.179	0	11	7
Segment: 2	8	0.7	6	0.6	1	0.1	0	0	1
Segment: 3	54	1	36	0.8	9	0.2	0	5	4
Segment: 4	14	1	9	0.75	3	0.25	0	1	1
Segment: 5	67	1	33	0.66	17	0.34	0	8	9
Segment: 6	45	1	23	0.697	10	0.303	0	6	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	5	0.5	5	0.5	0	0	0	0	0
Totals:	267	6.2	158	4.828	50	1.372	0	31	28

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	Amy Wilke		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Travis Grablander		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	Colorado Springs Utilities	Corey Walker		Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio	Tricia Bynum	Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	NB Power Corporation	Jeffrey Streifling		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		None	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Third-Party Comments
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		None	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Negative	Comments Submitted
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		Affirmative	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Dane Rogers	Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Tony Hua		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Third-Party Comments
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Georgia System Operations Corporation	Katrina Lyons		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	George Pino		None	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	AEP	Thomas Foltz		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	American Municipal Power	Amy Ritts		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Negative	Third-Party Comments
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Third-Party Comments
5	Grid Strategies LLC	Michael Goggin		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Muscatine Power and Water	Chance Back		Abstain	N/A
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		None	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Affirmative	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Affirmative	N/A
5	Tennessee Valley Authority	Darren Boehm		Abstain	N/A
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Russell Ferrell		None	N/A
6	Manitoba Hydro	Brandin Stoesz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Muscatine Power and Water	Nicholas Burns		Abstain	N/A
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tennessee Valley Authority	Armando Rodriguez		Abstain	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Affirmative	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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Showing 1 to 267 of 267 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/350)
Ballot Name: 2020-02 Modifications to PRC-024 (Generator Ride-through) Implementation Plan AB 4 OT
Voting Start Date: 9/24/2024 12:01:00 AM
Voting End Date: 10/4/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 4
Total # Votes: 240
Total Ballot Pool: 271
Quorum: 88.56
Quorum Established Date: 10/4/2024 9:19:35 AM
Weighted Segment Value: 77.89

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	75	1	45	0.833	9	0.167	1	12	8
Segment: 2	8	0.7	6	0.6	1	0.1	0	0	1
Segment: 3	55	1	37	0.804	9	0.196	0	5	4
Segment: 4	14	1	9	0.75	3	0.25	0	1	1
Segment: 5	68	1	34	0.667	17	0.333	0	7	10
Segment: 6	46	1	23	0.697	10	0.303	0	6	7
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	5	0.4	4	0.4	0	0	0	1	0
Totals:	271	6.1	158	4.751	49	1.349	1	32	31

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	Amy Wilke		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Travis Grablander		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	Colorado Springs Utilities	Corey Walker		Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio	Tricia Bynum	Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	No Comment Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		None	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	SaskPower	Wayne Guttormson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Third-Party Comments
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		None	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Negative	Comments Submitted
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		Affirmative	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Dane Rogers	Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Tony Hua		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Third-Party Comments
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Georgia System Operations Corporation	Katrina Lyons		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Seminole Electric Cooperative, Inc.	George Pino		None	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	American Municipal Power	Amy Ritts		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Third-Party Comments
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Chance Back		Abstain	N/A
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		None	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Affirmative	N/A
5	Tennessee Valley Authority	Darren Boehm		Abstain	N/A
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Russell Ferrell		None	N/A
6	Manitoba Hydro	Brandin Stoesz		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Abstain	N/A
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Abstain	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Affirmative	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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Showing 1 to 271 of 271 entries

BALLOT RESULTS

Ballot Name: 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-029-1 | Non-binding Poll AB 4 NB
Voting Start Date: 9/24/2024 12:01:00 AM
Voting End Date: 10/4/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 4
Total # Votes: 218
Total Ballot Pool: 251
Quorum: 86.85
Quorum Established Date: 10/4/2024 9:20:15 AM
Weighted Segment Value: 73.6

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	71	1	41	0.82	9	0.18	13	8
Segment: 2	7	0.3	2	0.2	1	0.1	3	1
Segment: 3	51	1	30	0.769	9	0.231	7	5
Segment: 4	14	1	9	0.75	3	0.25	1	1
Segment: 5	62	1	28	0.636	16	0.364	8	10
Segment: 6	41	1	17	0.654	9	0.346	7	8
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0
Segment: 9	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	5	0.4	4	0.4	0	0	1	0
Totals:	251	5.7	131	4.229	47	1.471	40	33

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	American Transmission Company, LLC	Amy Wilke		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Travis Grablander		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Comments Submitted
1	Colorado Springs Utilities	Corey Walker		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio	Tricia Bynum	Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		None	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		None	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Negative	Comments Submitted
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		Affirmative	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Dane Rogers	Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Tony Hua		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Georgia System Operations Corporation	Katrina Lyons		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	George Pino		None	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Comments Submitted
5	Grid Strategies LLC	Michael Goggin		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Muscatine Power and Water	Chance Back		Abstain	N/A
5	National Grid USA	Robin Berry		Negative	Comments Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		None	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Affirmative	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Russell Ferrell		None	N/A
6	Muscatine Power and Water	Nicholas Burns		Abstain	N/A
6	New York Power Authority	Shelly Dineen		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Gerry Dunbar		Affirmative	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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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

Draft 3 of PRC-024-4 is posted for final ballot. Non-substantive corrections were identified during the last additional ballot. This draft includes those corrections.

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023
25-day formal comment period with initial ballot	March 27 - April 22, 2024
15-day formal comment period and additional ballot	June 18 – July 8, 2024

Anticipated Actions	Date
Final ballot	September 25 – September 30, 2024
Board Adoption	October 8, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

A. Introduction

1. **Title:** **Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and Type 2 Wind Resources, and Synchronous Condensers**

2. **Number:** **PRC-024-4**

3. **Purpose:** To assure that protection of synchronous generators, type 1 and type 2 wind resources, and synchronous condensers do not cause tripping during defined frequency and voltage excursions in support of the Bulk Power System (BPS).

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Generator Owners that apply protection listed in Sections 4.2.1 or 4.2.2.

4.1.2. Transmission Owners that apply protection listed in Section 4.2.2.

4.1.3. 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.

4.1.4. 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 trip; and are applied to the following:

4.2.1.1 Bulk Electric System (BES) synchronous generators.

4.2.1.2 BES GSU transformer(s) for synchronous generators.

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

4.2.1.4 Individual dispersed power producing type 1 or type 2 wind resource(s) identified in the BES Definition, Inclusion I4.

[1] For the purpose of this standard, the MPT is the power transformer that steps up voltage from multiple small synchronous generators (e.g. multiple small hydro generators connecting to a common bus) or from a type 1 or type 2 wind resource collector station to transmission voltage .

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

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

4.2.1.5 Elements that are designed primarily for the delivery of capacity from multiple synchronous generators connecting to a common bus or individual dispersed power producing type 1 or type 2 wind resources identified in the BES Definition, Inclusion I4, to the point where those resources aggregate to greater than 75 MVA.

4.2.1.6 MPT of multiple synchronous generators connecting to a common bus or MPT of individual dispersed power producing type 1 or type 2 wind resources as identified in the BES Definition, Inclusion I4.

4.2.2 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 transmission connected synchronous condensers; or (ii) provide signals to trip transmission connected synchronous condenser and are applied to the following:

4.2.2.1 BES synchronous condensers

4.2.2.2 BES step-up transformer(s) for synchronous condensers.

4.2.2.3 High-side of the synchronous condenser-connected unit auxiliary transformer (UAT).

4.2.3 **Exemptions:** Protection on all auxiliary equipment within the synchronous generator, type 1 or type 2 wind resource, or synchronous condenser Facility.

5. **Effective Date:** See Implementation Plan for PRC-024-4

B. Requirements and Measures

R1. Each Generator Owner and Transmission Owner shall set applicable frequency protection[4] in accordance with PRC-024-4 Attachment 1 such that the applicable protection does not cause the Facility to which it is applied to trip within the "no trip zone" during a frequency excursion with the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Applicable frequency protection may be set to trip within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M1. Each Generator Owner and Transmission Owner shall have evidence that the applicable frequency protection has been set in accordance with Requirement R1, such as dated setting sheets, calibration sheets, calculations, or other documentation.

R2. Each Generator Owner and Transmission Owner shall set applicable voltage protection[5] in accordance with PRC-024-4 Attachment 2, such that the applicable protection does not cause the Facility to which it is applied to trip within the "no trip zone" during a voltage excursion at the high-side of the GSU or MPT, 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-024-4 Attachment 2, then the Generator Owner or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- Applicable voltage protection may be set to trip during a voltage excursion within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M2. 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.

R3. Each Generator Owner and Transmission Owner shall document each known regulatory or equipment limitation[6] that prevents its Facility, with applicable frequency or voltage protection from meeting the 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]*

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[4] 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 synchronous generator(s), type 1 or type 2 wind resource(s), or synchronous condenser(s); or (ii) provide signals to trip the same Facilities.

[5] Ibid.

[6] Excludes limitations caused by the setting capability of the frequency, voltage, and volts per hertz protective relays applied to the synchronous generator(s), type 1 and type 2 wind resource(s), and synchronous condenser(s). This does not exclude limitations originating in the equipment protected by the relay(s).

3.1. The Generator Owner and Transmission 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 and Transmission Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations 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.

R4. Each Generator Owner and Transmission Owner shall provide its applicable protection settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated Facility 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 settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of protection setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Generator Owner and Transmission Owner shall have evidence that it communicated applicable protection settings in accordance with Requirement R4, such as dated emails, correspondence or other evidence and copies of any requests it has received for that information.

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.

   1.2. **Evidence Retention:** 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 and Transmission Owner shall keep data or evidence of Requirements R1 through R4 for five years or until the next audit, whichever is longer.
   - If a Generator Owner or Transmission 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.

   1.3. **Compliance Monitoring and Enforcement 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.

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 or Transmission Owner failed to set its applicable frequency protection so that it does not trip according to Requirement R1.
R2.	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 according to Requirement R2.
R3.	The Generator Owner or Transmission 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 or Transmission 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 or Transmission 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 or Transmission 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 or Transmission Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				days of identifying the limitation.
R4.	The Generator Owner or Transmission Owner provided its protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner or provided protection settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner or Transmission Owner failed to provide its protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner failed to provide protection settings within 150 calendar days of a written request.

D. Regional Variances

D.A. Variance for the Quebec Interconnection

This Variance 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.

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

D.A.2. Each Generator Owner and Transmission Owner shall set applicable voltage protection[7] in accordance with PRC-024 Attachment 2A, such that the applicable protection does not cause the Facility to which it is applied to trip within the “no trip zone” during a voltage excursion 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”.
- Applicable voltage protection may be set to trip during a voltage excursion within a portion of 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.

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,

[7] 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 synchronous generator(s), type 1 or type 2 wind resource(s), or synchronous condenser(s); or (ii) provide signals to trip the same Facilities.

each Generator Owner or Transmission Owner that owns facilities[8] 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.

[8] Facilities in the strategic power plants include facilities with synchronous generator(s) 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 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 facilities in the strategic power plants between 31 days and 45 days after its designation.	The Planning Coordinator designated strategic power plants at least once every five calendar years but notified each Generator Owner or Transmission Owner that owns facilities in the strategic power plants between 46 days and 60 days after its designation.	The Planning Coordinator failed to designate, at least once every five years, the strategic power plants that must comply with Attachment 2A. 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 its designation.

E. Associated Documents

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	February 6, 2020	Adopted by the NERC Board of Trustees	Standard revised in Project 2018-04
3	July 9, 2020	FERC Letter Order approved PRC024-3. Docket No. RD20-7-000	
3	July 17, 2020	Effective Date	10/1/2022
4	August 2, 2024	Revisions made by the 2020-02 Drafting Team	Revision accounts for changes with PRC-029-1 as part of Milestone 2 of NERC's work plan to address FERC Order No. 901.

Attachment 1
(Frequency No Trip Boundaries by Interconnection[9])

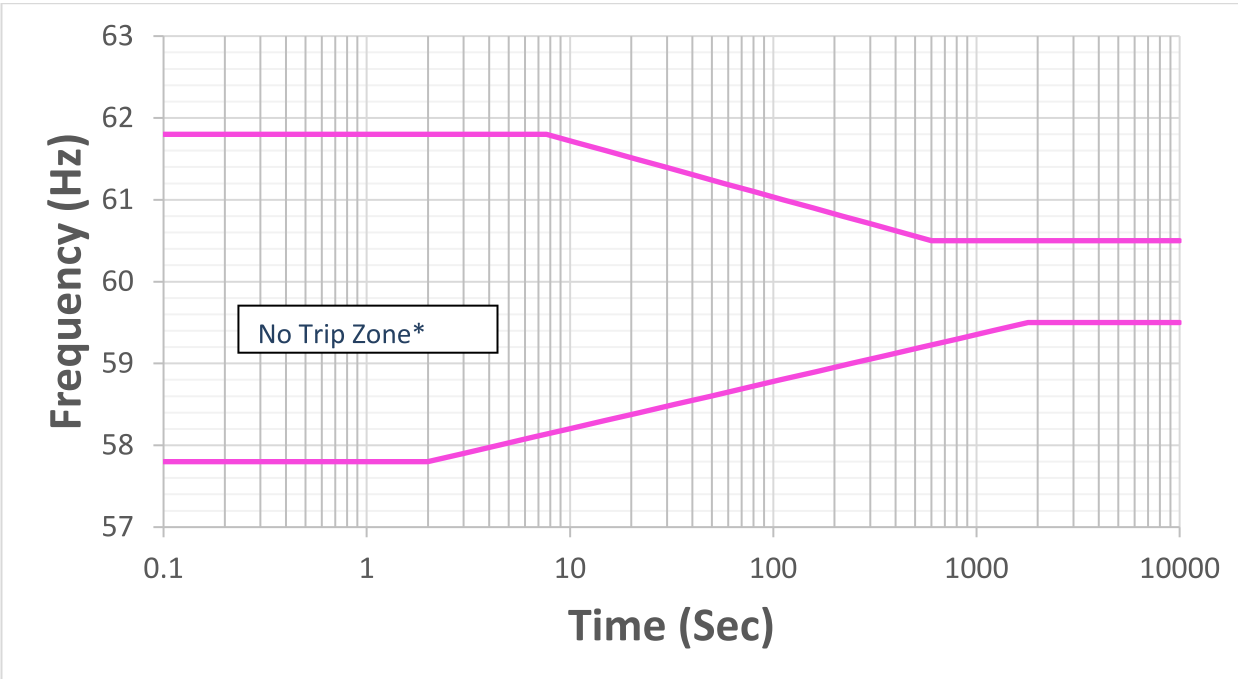

Figure 1: Eastern Interconnection Boundaries

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

Table 1: 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[10]	≤57.8	Instantaneous[11]
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

[9] 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.

[10] 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.

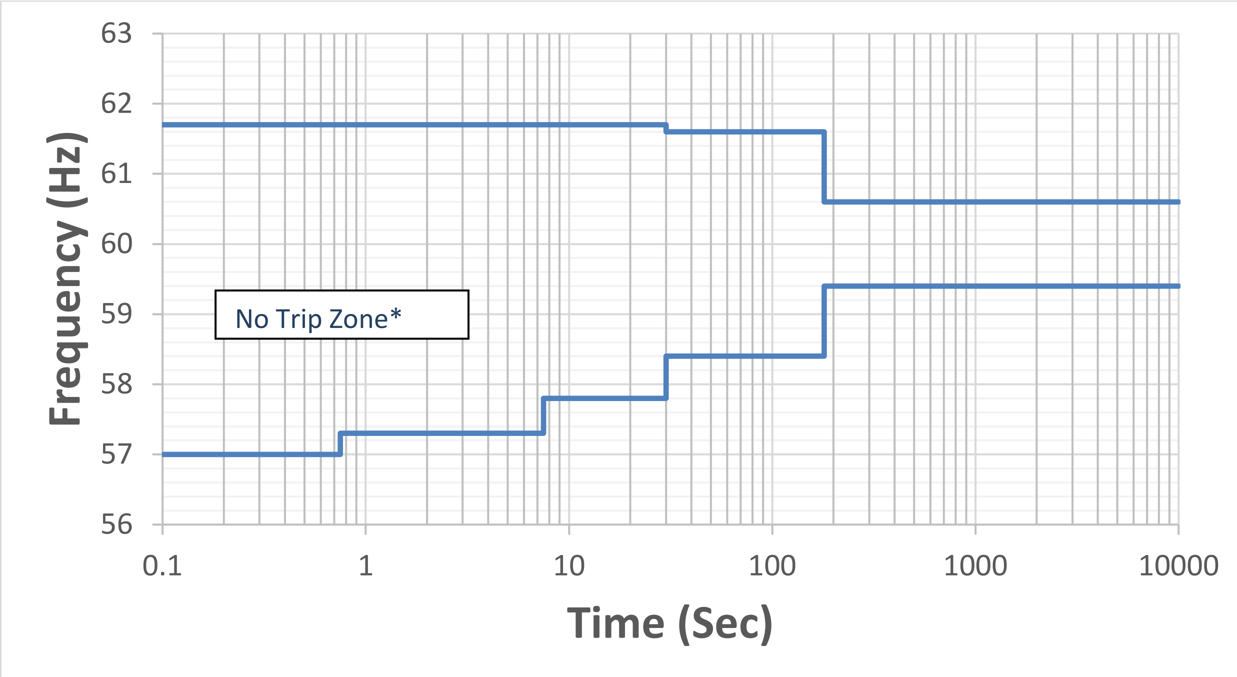

Figure 2: Western Interconnection Boundaries

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

Table 2: 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[11]	≤57.0	Instantaneous[11]
≥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

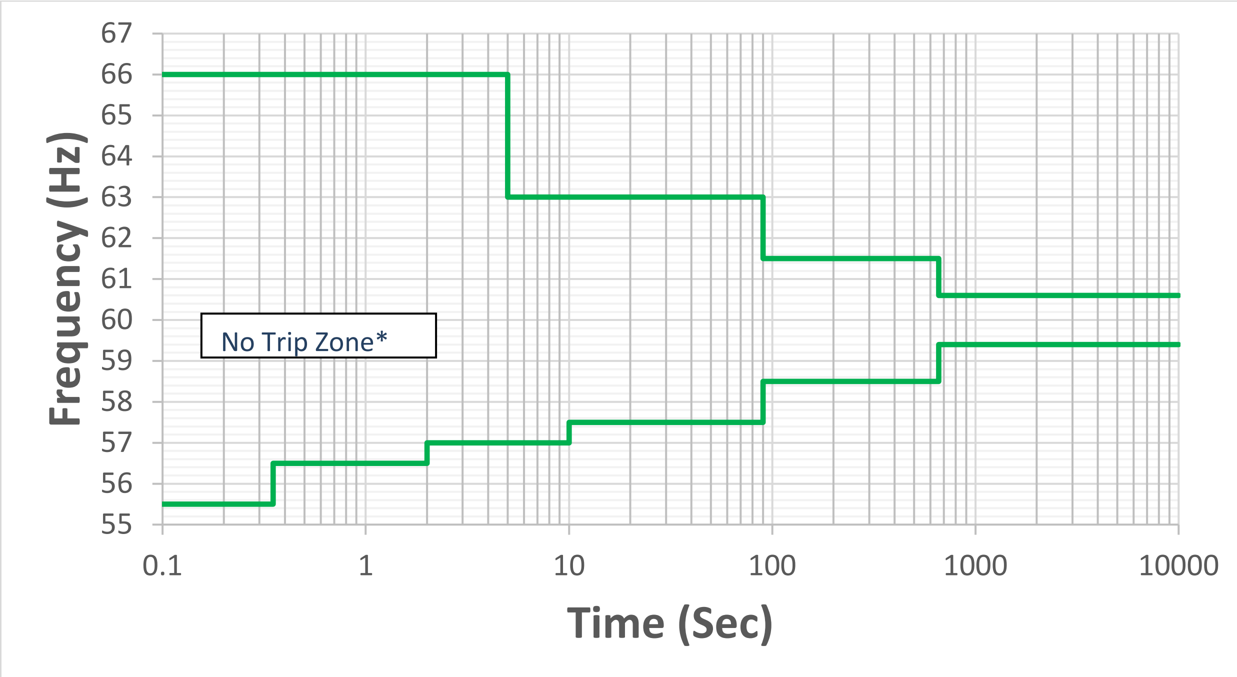

Figure 3: Quebec Interconnection Boundaries

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

Table 3: 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[11]	<55.5	Instantaneous[11]
≥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

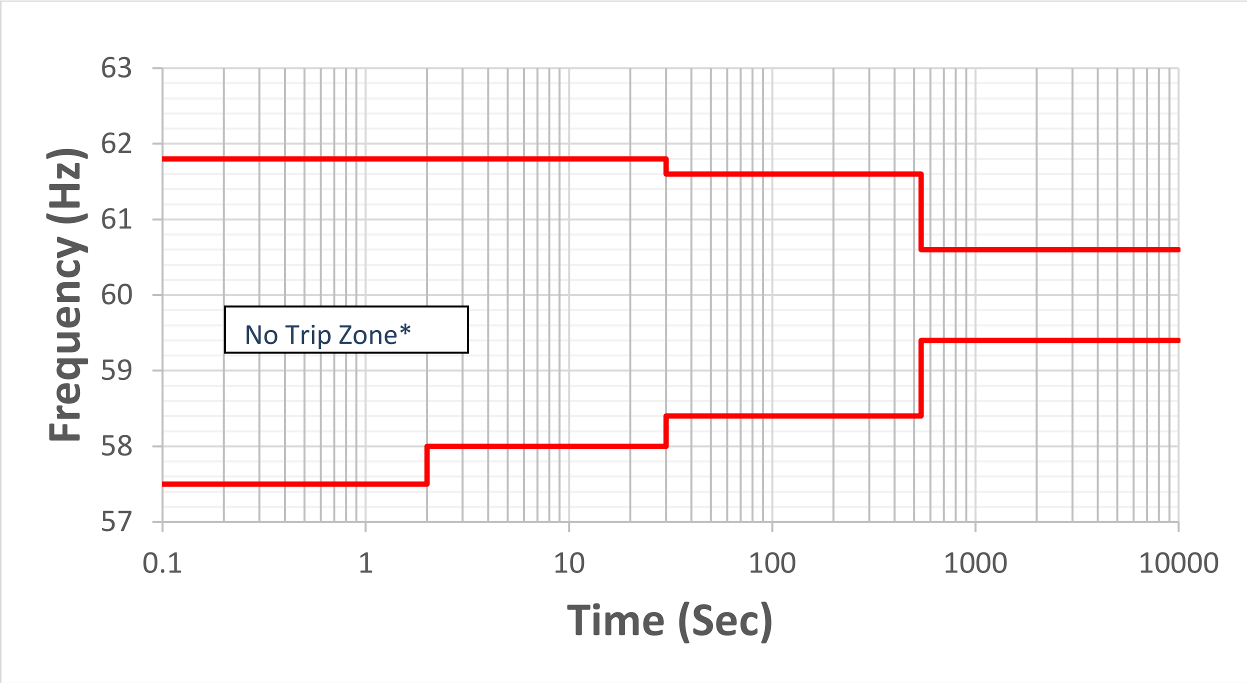

Figure 4: ERCOT Interconnection Boundaries

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

Table 4: 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[11]	≤57.5	Instantaneous[11]
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024 — Attachment 2

(Voltage No-Trip Boundaries – Eastern, Western, and ERCOT Interconnections)

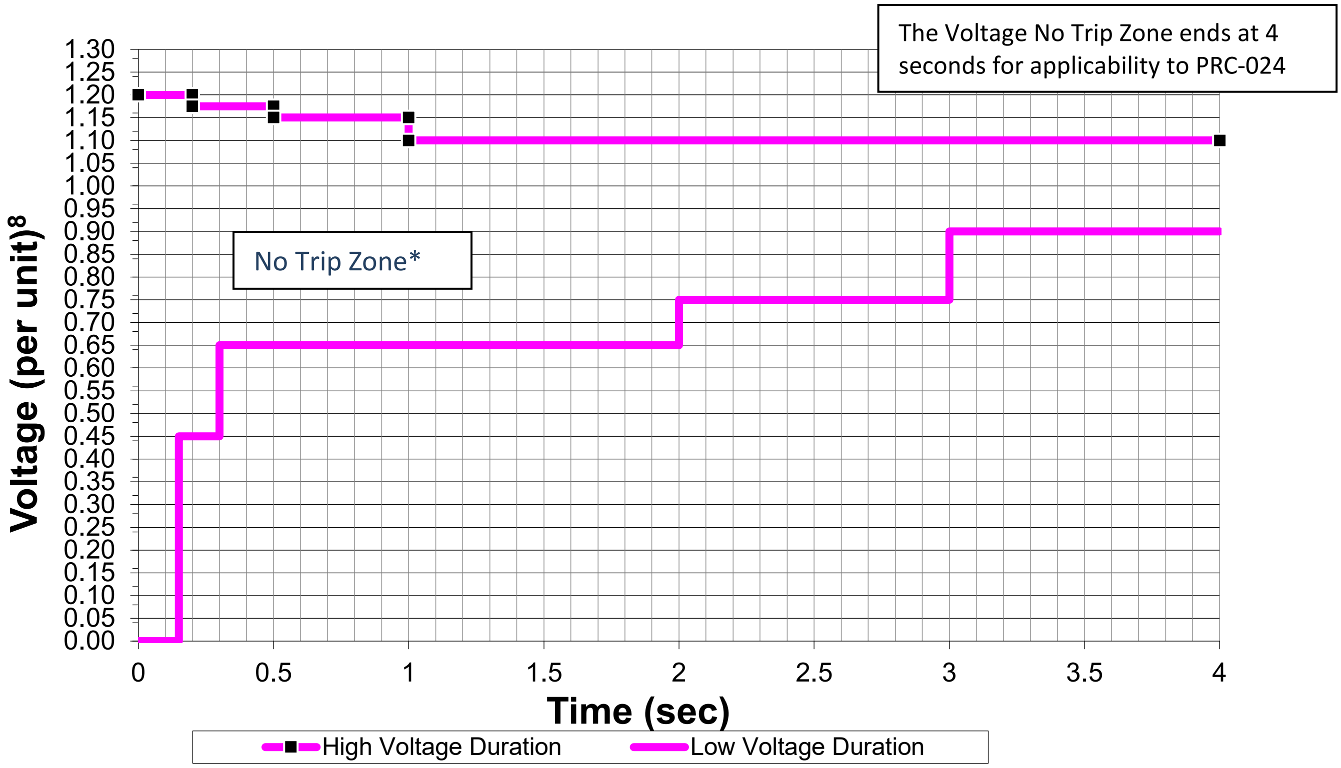

Figure 5: Voltage No-Trip Boundaries – Eastern, Western, and ERCOT Interconnections

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

Table 5: Voltage Boundary Data Points

High Voltage Duration		Low Voltage Duration	
Voltage (per unit)	Minimum Time (sec)	Voltage (per unit)	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

Attachment 2: Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections

Boundary Details:

1. Unless otherwise specified by the Transmission Planner, the per unit voltage base for these boundaries is the nominal transmission system voltage (e.g., 100 kV, 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 400 kV, 500 kV, 765 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 boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase per unit voltage.
5. For applicability to PRC-024, the “no trip zone” ends at 4 seconds.

Evaluating Protection Settings:

The voltage values in the Attachment 2 voltage boundaries are voltages at the high-side of the GSU/MPT. For 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 conditions when evaluating protection settings:

a. The most probable real and reactive loading conditions for the synchronous generator, type 1 or 2 wind resources, or synchronous condenser under study.
b. All installed wind resource 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 or the collector station and the high-side of the GSU/MPT.
d. For dynamic simulations, the synchronous generator or condenser automatic voltage regulator is in automatic voltage control mode with associated limiters in service.

PRC-024— Attachment 2A
(Voltage No-Trip Boundaries – Quebec Interconnection)

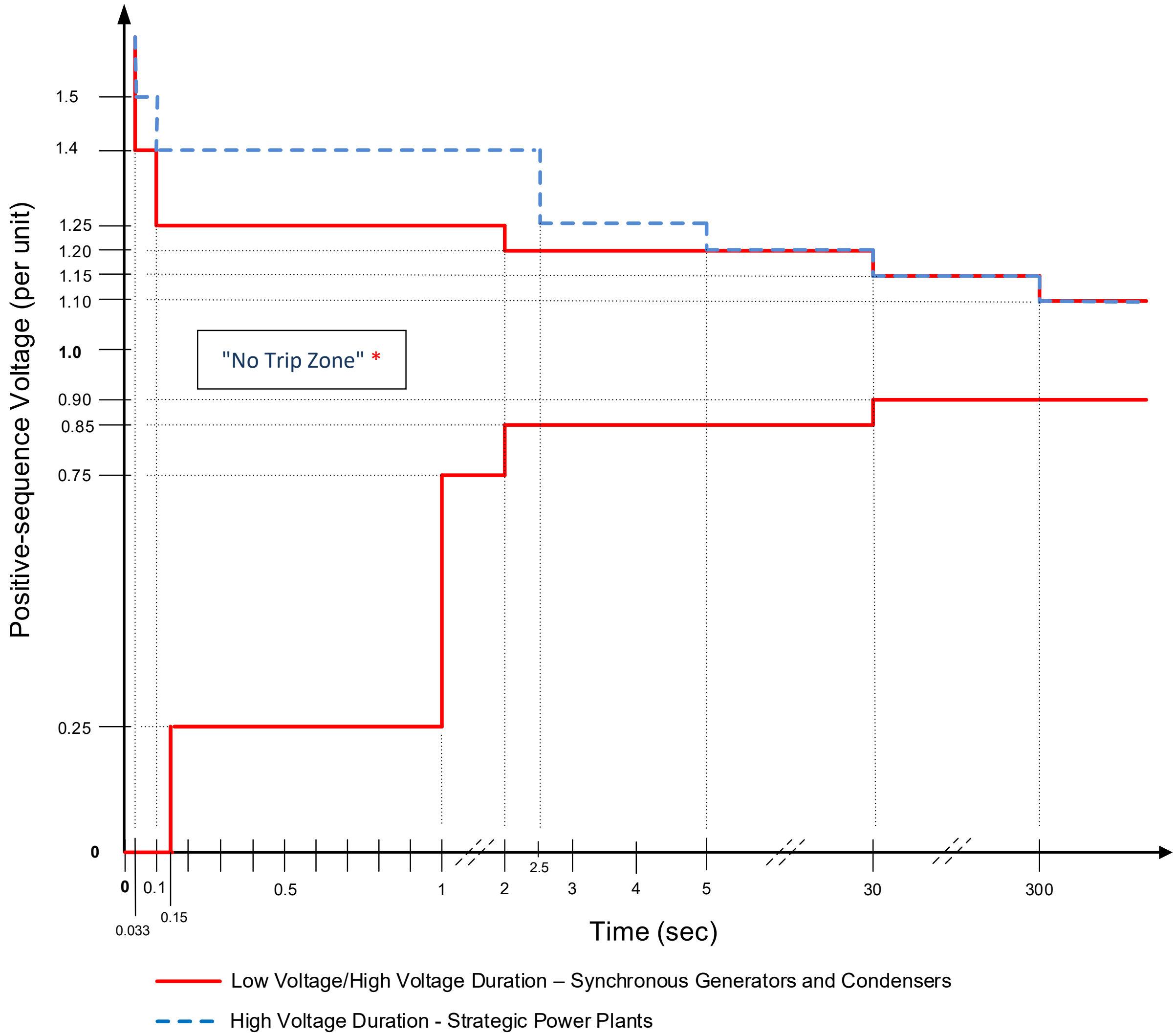

Figure 6: Voltage No-Trip Boundaries – Quebec Interconnection

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

Table 6: High Voltage Boundary Data Points – Quebec Interconnection

High Voltage Duration for all Synchronous Generators and Condensers		High Voltage Duration for strategic Power Plants	
Voltage (per unit)	Minimum Time (sec)	Voltage (per unit)	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 7: Low Voltage Boundary Data Points – Quebec Interconnection

Low Voltage Duration for all Synchronous Generators and Condensers	
Voltage (per unit)	Minimum Time (sec)
<0.25	0.15
<0.75	1.00
<0.85	2.00
<0.90	30
≥0.90	continuous

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 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.

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

Draft 3 of PRC-024-4 is posted for final ballot. Non-substantive corrections were identified during the last additional ballot. This draft includes those corrections.

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023
25-day formal comment period with initial ballot	March 27 - April 22, 2024
15-day formal comment period and additional ballot	June 18 – July 8, 2024

Anticipated Actions	Date
Final ballot	September 25 – September 30, 2024
Board Adoption	October 8, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

A. Introduction

1. **Title:** **Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and Type 2 Wind Resources, and Synchronous Condensers**

2. **Number:** **PRC-024-4**

3. **Purpose:** To assure that protection of synchronous generators, type 1 and type 2 wind resources, and synchronous condensers do not cause tripping during defined frequency and voltage excursions in support of the Bulk Power System (BPS).

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Generator Owners that apply protection listed in Sections 4.2.1 or 4.2.2.

4.1.2. Transmission Owners that apply protection listed in Section 4.2.2.

4.1.3. 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.

4.1.4. 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 trip; and are applied to the following:

4.2.1.1 Bulk Electric System (BES) synchronous generators.

4.2.1.2 BES GSU transformer(s) for synchronous generators.

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

4.2.1.4 Individual dispersed power producing type 1 or type 2 wind resource(s) identified in the BES Definition, Inclusion I4.

[1] For the purpose of this standard, the MPT is the power transformer that steps up voltage from multiple small synchronous generators (e.g. multiple small hydro generators connecting to a common bus) or from a type 1 or type 2 wind resource collector station to transmission voltage .

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

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

4.2.1.5 Elements that are designed primarily for the delivery of capacity from multiple synchronous generators connecting to a common bus or individual dispersed power producing type 1 or type 2 wind resources identified in the BES Definition, Inclusion I4, to the point where those resources aggregate to greater than 75 MVA.

4.2.1.6 MPT of multiple synchronous generators connecting to a common bus or MPT of individual dispersed power producing type 1 or type 2 wind resources as identified in the BES Definition, Inclusion I4.

4.2.2 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 transmission connected synchronous condensers; or (ii) provide signals to trip transmission connected synchronous condenser and are applied to the following:

4.2.2.1 BES synchronous condensers

4.2.2.2 BES step-up transformer(s) for synchronous condensers.

4.2.2.3 High-side of the synchronous condenser-connected unit auxiliary transformer (UAT).

4.2.3 **Exemptions:** Protection on all auxiliary equipment within the synchronous generator, type 1 or type 2 wind resource, or synchronous condenser Facility.

5. Effective Date: See Implementation Plan for PRC-024-4

B. Requirements and Measures

R1. Each Generator Owner and Transmission Owner shall set applicable frequency protection[4] in accordance with PRC-024-4 Attachment 1 such that the applicable protection does not cause the Facility to which it is applied to trip within the "no trip zone" during a frequency excursion with the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Applicable frequency protection may be set to trip within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M1. Each Generator Owner and Transmission Owner shall have evidence that the applicable frequency protection has been set in accordance with Requirement R1, such as dated setting sheets, calibration sheets, calculations, or other documentation.

R2. Each Generator Owner and Transmission Owner shall set applicable voltage protection[5] in accordance with PRC-024-4 Attachment 2, such that the applicable protection does not cause the Facility to which it is applied to trip within the "no trip zone" during a voltage excursion at the high-side of the GSU or MPT, 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-024-4 Attachment 2, then the Generator Owner or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- Applicable voltage protection may be set to trip during a voltage excursion within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M2. 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.

R3. Each Generator Owner and Transmission Owner shall document each known regulatory or equipment limitation[6] that prevents ~~an~~ its ~~synchronous generator, type 1 or type 2 wind resource, or synchronous condenser,~~Facility with applicable frequency or voltage protection from meeting the protection setting criteria in Requirements R1 or R2, including (but not limited to) study results, experience from

[4] 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 synchronous generator(s), type 1 or type 2 wind resource(s), or synchronous condenser(s); or (ii) provide signals to ~~same to~~ trip the same Facilities.

[5] Ibid.

[6] Excludes limitations caused by the setting capability of the frequency, voltage, and volts per hertz protective relays applied to the synchronous generator(s), type 1 and type 2 wind resource(s), and synchronous condenser(s). This does not exclude limitations originating in the equipment protected by the relay(s).

an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner and Transmission 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 and Transmission Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations 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.

R4. Each Generator Owner and Transmission Owner shall provide its applicable protection settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated Facility 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 settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of protection setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Generator Owner and Transmission Owner shall have evidence that it communicated applicable 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.

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.

   1.2. **Evidence Retention:** 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 and Transmission Owner shall keep data or evidence of Requirements R1 through R4 for five years or until the next audit, whichever is longer.
   - If a Generator Owner or Transmission 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.

   1.3. **Compliance Monitoring and Enforcement 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.

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 or Transmission Owner failed to set its applicable frequency protection so that it does not trip according to Requirement R1.
R2.	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 according to Requirement R2.
R3.	The Generator Owner or Transmission 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 or Transmission 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 or Transmission 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 or Transmission 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 or Transmission Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				days of identifying the limitation.
R4.	The Generator Owner or Transmission Owner provided its protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner or provided protection settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner or Transmission Owner failed to provide its protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner failed to provide protection settings within 150 calendar days of a written request.

D. Regional Variances

D.A. Variance for the Quebec Interconnection

This Variance 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.

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

D.A.2. Each Generator Owner and Transmission Owner shall set applicable voltage protection[7] in accordance with PRC-024 Attachment 2A~~B~~, such that the applicable protection does not cause the Facility to which it is applied to trip within the "no trip zone" during a voltage excursion 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".
- Applicable voltage protection may be set to trip during a voltage excursion within a portion of the "no trip zone" of PRC-024 Attachment 2A~~B~~ 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~~B~~, then the Generator Owner or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.

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~~B~~ and notify, within 30 calendar days of its designation,

[7] 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 synchronous generator(s), type 1 or type 2 wind resource(s), or synchronous condenser(s); or (ii) provide signals to ~~same to~~ trip the same Facilities.

each Generator Owner or Transmission Owner that owns facilities[8] 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.

[8] Facilities in the strategic power plants include facilities with synchronous generator(s) 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 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 facilities in the strategic power plants between 31 days and 45 days after its designation.	The Planning Coordinator designated strategic power plants at least once every five calendar years but notified each Generator Owner or Transmission Owner that owns facilities in the strategic power plants between 46 days and 60 days after its designation.	The Planning Coordinator failed to designate, at least once every five years, the strategic power plants that must comply with Attachment 2B. 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 its designation.

E. Associated Documents

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	February 6, 2020	Adopted by the NERC Board of Trustees	Standard revised in Project 2018-04
3	July 9, 2020	FERC Letter Order approved PRC024-3. Docket No. RD20-7-000	
3	July 17, 2020	Effective Date	10/1/2022
4	August 2, 2024	Revisions made by the 2020-02 Drafting Team	Revision accounts for changes with PRC-029-1 as part of Milestone 2 of NERC's work plan to address FERC Order No. 901.

Attachment 1
(Frequency No Trip Boundaries by Interconnection[9])

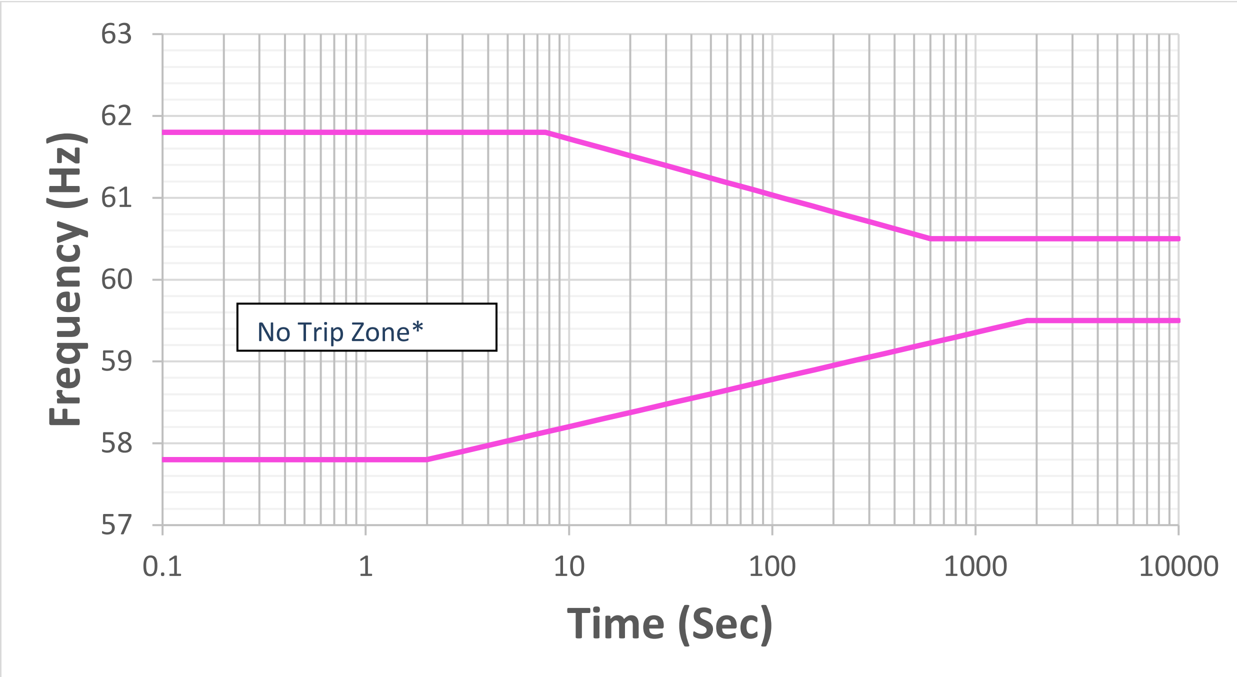

Figure 1: Eastern Interconnection Boundaries

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

Table 1: 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[10]	≤57.8	Instantaneous[11]
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

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[9] 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.

[10] 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.

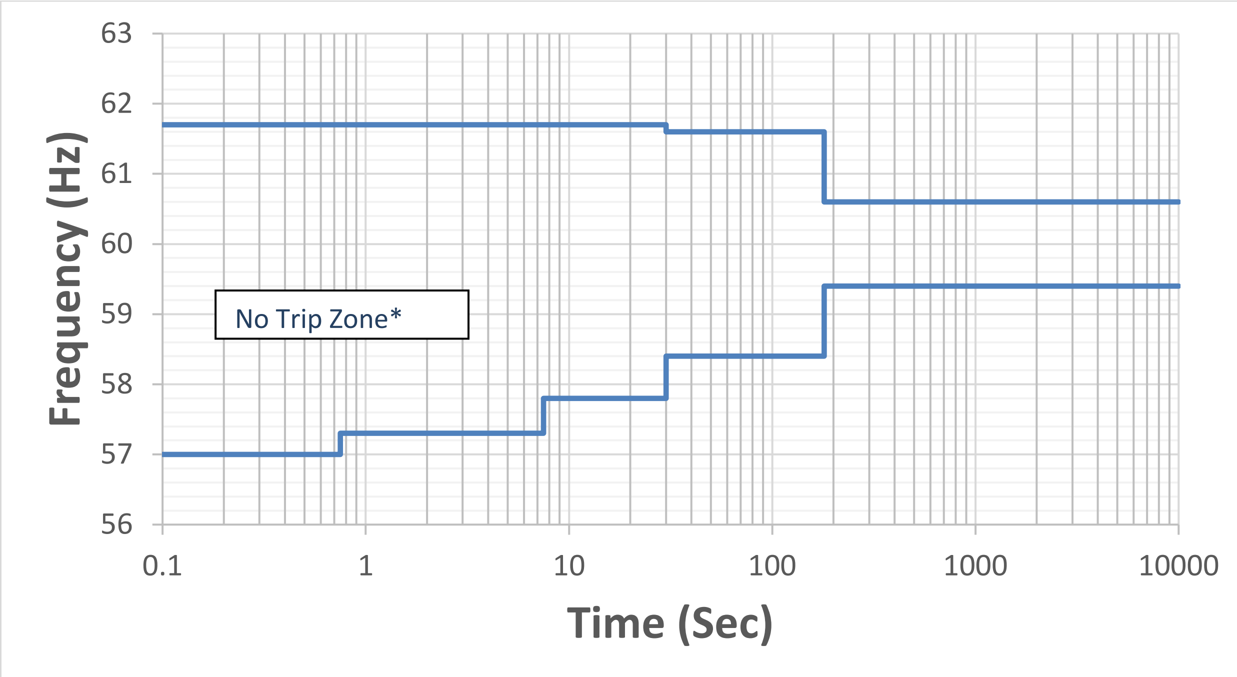

Figure 2: Western Interconnection Boundaries

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

Table 2: 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[11]	≤57.0	Instantaneous[11]
≥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

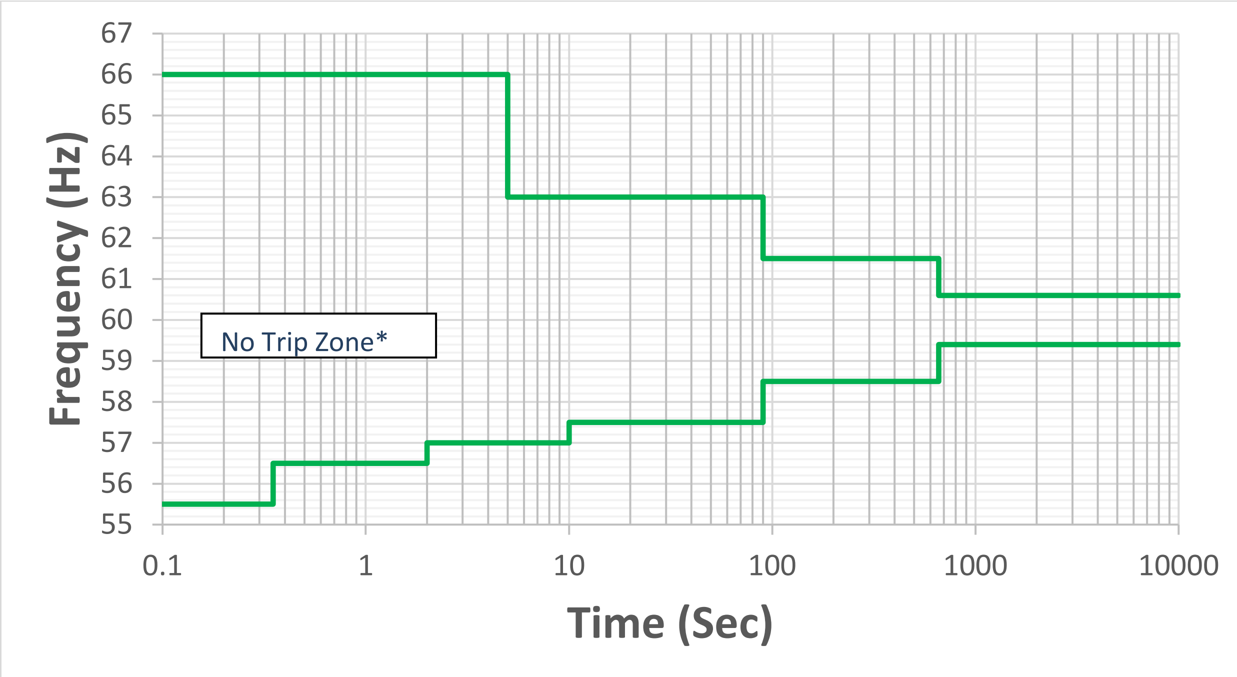

Figure 3: Quebec Interconnection Boundaries

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

Table 3: 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[11]	<55.5	Instantaneous[11]
≥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

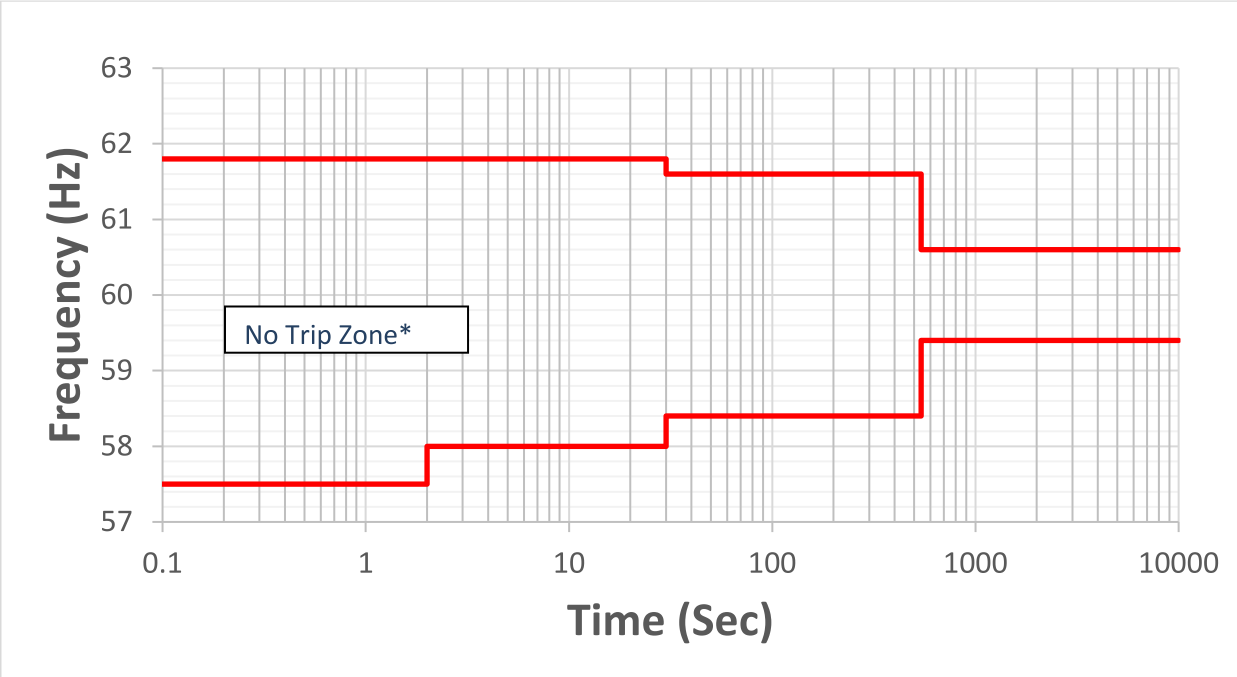

Figure 4: ERCOT Interconnection Boundaries

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

Table 4: 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[11]	≤57.5	Instantaneous[11]
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024 — Attachment 2

(Voltage No-Trip Boundaries – Eastern, Western, and ERCOT Interconnections)

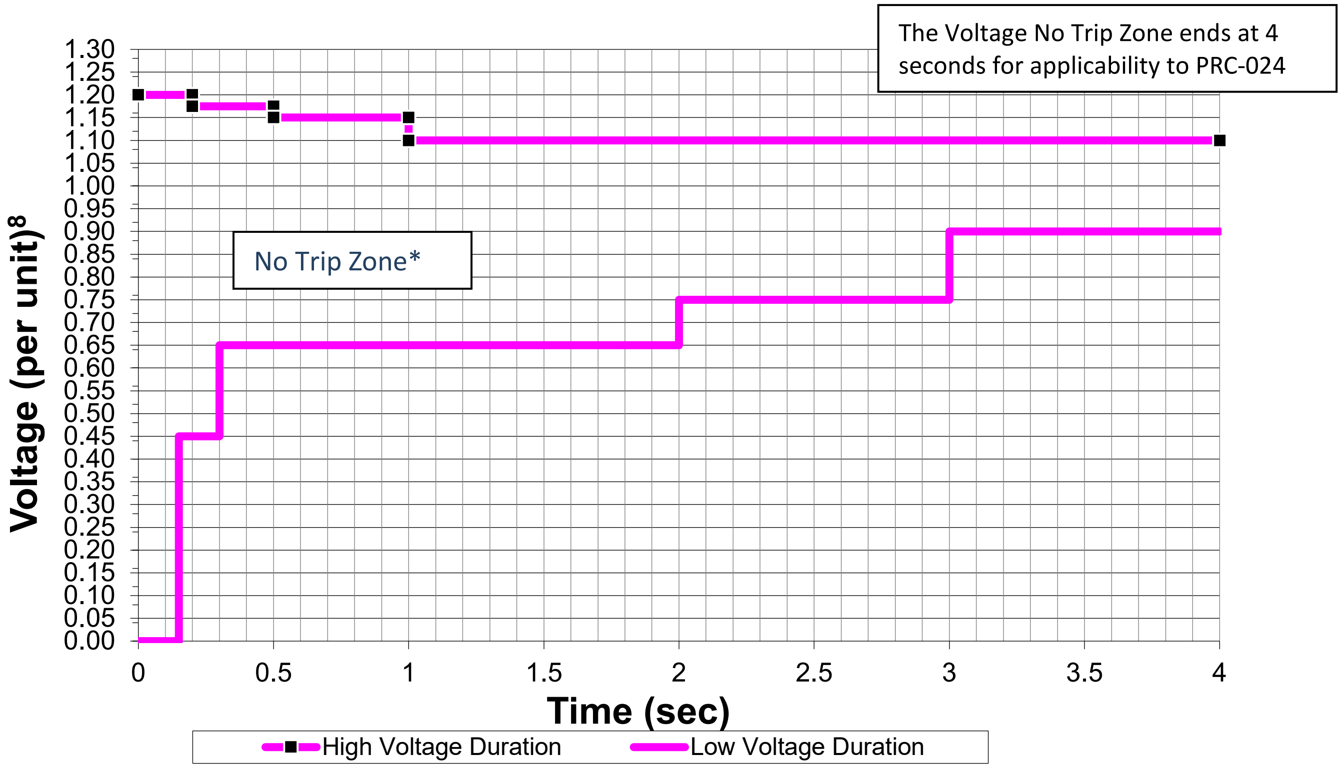

Figure 5: Voltage No-Trip Boundaries – Eastern, Western, and ERCOT Interconnections

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

Table 5: Voltage Boundary Data Points

High Voltage Duration		Low Voltage Duration	
Voltage (per unit)	Minimum Time (sec)	Voltage (per unit)	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

Attachment 2~~A~~: Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections

Boundary Details:

1. Unless otherwise specified by the Transmission Planner, the per unit voltage base for these boundaries is the nominal transmission system voltage (e.g., 100 kV, 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 400 kV, 500 kV, 765 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 boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase per unit voltage.
5. For applicability to PRC-024, the "no trip zone" ends at 4 seconds.

Evaluating Protection Settings:

The voltage values in the Attachment 2 voltage boundaries are voltages at the high-side of the GSU/MPT. For 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 conditions when evaluating protection settings:

a. The most probable real and reactive loading conditions for the synchronous generator, type 1 or 2 wind resources, or synchronous condenser ~~unit~~ under study.

b. All installed wind resource~~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 synchronous generator or condenser automatic voltage regulator is in automatic voltage control mode with associated limiters in service.

PRC-024— Attachment 2A~~B~~
(Voltage No-Trip Boundaries – Quebec Interconnection)

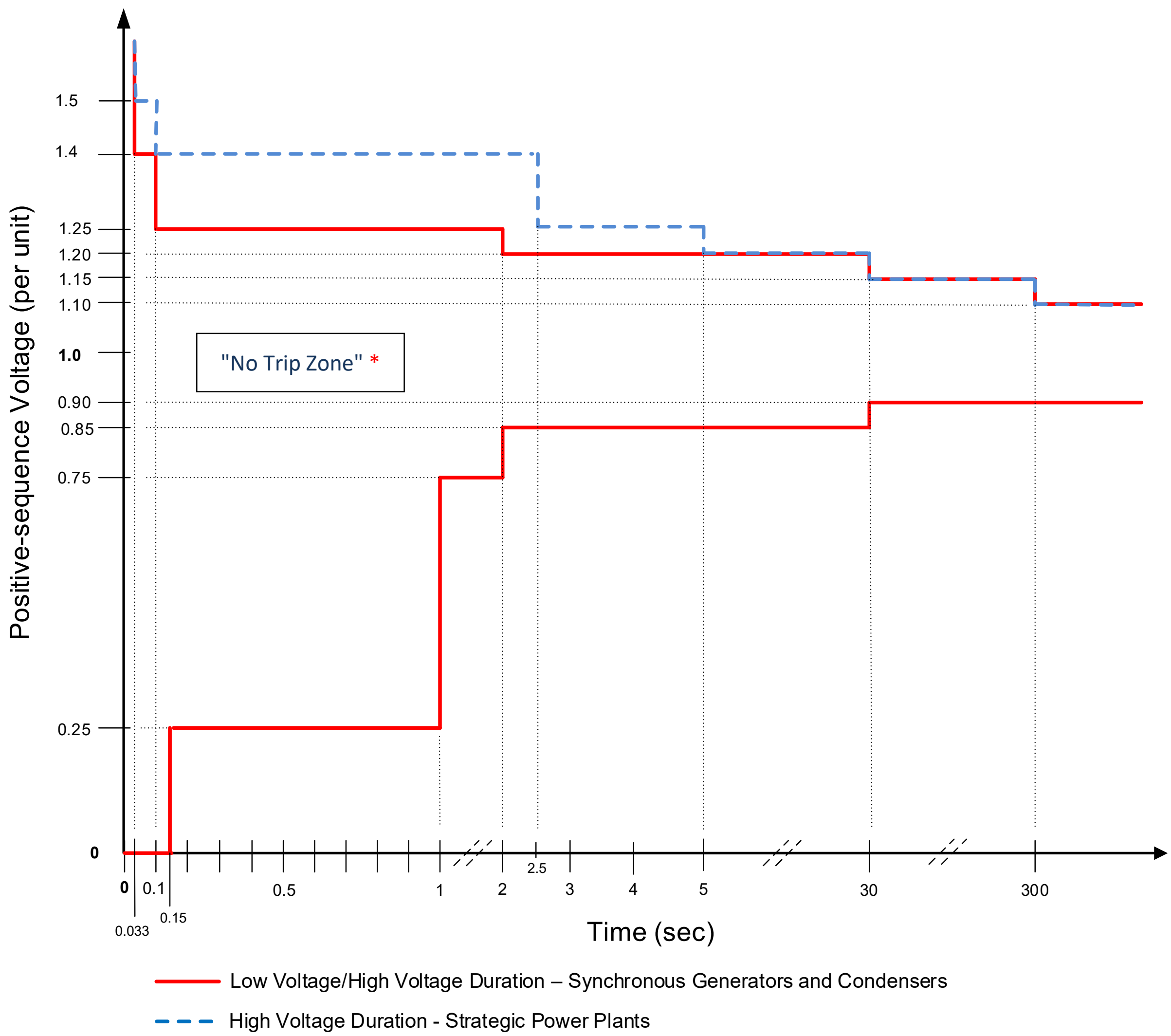

Figure 6: Voltage No-Trip Boundaries – Quebec Interconnection

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

Table 6: High Voltage Boundary Data Points – Quebec Interconnection

High Voltage Duration for all Synchronous Generators and Condensers		High Voltage Duration for strategic Power Plants	
Voltage (per unit)	Minimum Time (sec)	Voltage (per unit)	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 7: Low Voltage Boundary Data Points – Quebec Interconnection

Low Voltage Duration for all Synchronous Generators and Condensers	
Voltage (per unit)	Minimum Time (sec)
<0.25	0.15
<0.75	1.00
<0.85	2.00
<0.90	30
≥0.90	continuous

Attachment 2A~~C~~: 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 2B voltage boundaries are voltages at the high-side of the GSU/MPT. For 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.

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

Draft 3 of PRC-024-4 is posted for final ballot. Non-substantive corrections were identified during the last additional ballot. This draft includes those corrections.

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023
25-day formal comment period with initial ballot	March 27 - April 22, 2024
15-day formal comment period and additional ballot	June 18 – July 8, 2024

Anticipated Actions	Date
Final ballot	September 25 – September 30, 2024
Board Adoption	October 8, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

A. Introduction

1. **Title:** **Frequency and Voltage Protection Settings for Synchronous Generators~~ing~~, Type 1 and Type 2 Wind Resources, and Synchronous Condensers**
2. **Number:** **PRC-024-4~~3~~**
3. **Purpose:** To assure~~set~~ that protection of~~ such that~~ synchronous generators~~ing~~, type 1 and type 2 wind resource~~(s)~~, and synchronous condensers do not cause tripping ~~remain connected~~ during defined frequency and voltage excursions in support of the Bulk ~~Electric~~ Power System (BP~~E~~S).
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Generator Owners that apply protection listed in Section 4.2.1 or 4.2.2.

4.1.2 Transmission Owners that apply protection listed in Section 4.2.2.

~~4.1.2~~4.1.3 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~~4.1.4 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 Bulk Electric (BES) synchronous generators~~ing resource(s)~~.

4.2.1.2 BES GSU transformer(s) for synchronous generators.

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

4.2.1.4 Individual dispersed power producing type 1 or type 2 wind resource(s) identified in the BES Definition, Inclusion I4.

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[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.

4.2.1.5 Elements that are designed primarily for the delivery of capacity from multiple synchronous generators connecting to a common bus or~~the~~ individual dispersed power producing type 1 or type 2 wind resources 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 multiple synchronous generators connecting to a common bus or MPT of individual dispersed power producting type 1 or type 2 wind resource~~(~~s~~)~~ as identified in the BES Definition, Inclusion I4.

4.2.2 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 transmission connected synchronous condensers; or (ii) provide signals to trip transmission connected synchronous condenser and are applied to the following:

4.2.2.1 BES synchronous condensers

4.2.2.2 BES step-up transformer(s) for synchronous condensers.

4.2.2.3 High-side of the synchronous condenser-connected unit auxiliary transformer (UAT).

~~4.2.2~~4.2.3 **Exemptions:** Protection on all auxiliary equipment within the synchronous generator~~ing~~, type 1 or type 2 wind resource, or synchronous condenser Facility.

5. **Effective Date:** See the Implementation Plan for PRC-024-4~~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~~

B. Requirements and Measures

R1. Each Generator Owner and Transmission Owner shall set ~~its~~ applicable frequency protection[5] in accordance with PRC-024-4 Attachment 1 such that the applicable protection does not cause the ~~generating resource~~Facility to which it is applied to trip ~~or cease injecting current~~ within the "no trip zone" during a frequency excursion with the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Applicable frequency protection may 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.

M1. Each Generator Owner and Transmission Owner shall have evidence that the -applicable frequency protection has been set in accordance with Requirement R1, such as dated setting sheets, calibration sheets, calculations, or other documentation.

R2. Each Generator Owner and Transmission Owner shall set its applicable voltage protection[6~~5~~] in accordance with PRC-024-4 Attachment 2, such that the applicable protection does not cause the ~~generating resource~~Facility to which it is applied to trip ~~or cease injecting current~~ within the "no trip zone" during a voltage excursion at the high- side of the GSU or MPT,- 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-024-4 Attachment 2, then the Generator Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- Applicable voltage protection may be set to trip ~~or cease injecting current~~ during a voltage excursion within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M2. 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.

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[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 synchronous generat~~ors~~ing, type 1 or type 2 wind resource(s), or synchronous condenser(s); or (ii) provide signals to ~~the generating resource(s) to either~~ trip ~~or cease injecting current~~the same Facilties.

[6] Ibid

R3. Each Generator Owner and Transmission Owner shall document each known regulatory or equipment limitation[7] that prevents ~~an applicable generating resource(s)~~its Facility, with applicable frequency or voltage protection from meeting the 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]*

3.1. The Generator Owner and Transmission 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 and Transmission Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations 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.

R4. Each Generator Owner and Transmission Owner shall provide its applicable protection settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated Facility ~~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 settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of protection setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Generator Owner and Transmission Owner shall have evidence that it communicated applicable 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.

[7] Excludes limitations caused by the setting capability of the frequency, voltage, and volts per hertz protective relays applied to the synchronous ~~for the~~ generators~~ing~~, type 1 or type 2 wind resource(s), and synchronous condenser(s). This does not exclude limitations originating in the equipment protected by the relay. ~~This also does not exclude limitations of frequency, voltage, and volts per hertz protection embedded in control systems~~.

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.

   1.2. **Evidence Retention:** 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 and Transmission Owner shall keep data or evidence Requirement R1 through R4; for five~~3~~ years or until the next audit, whichever is longer.
   - If a Generator Owner or Transmission 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.

   1.3. **Compliance Monitoring and Assessment 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.

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 or Transmission Owner failed to set its applicable frequency protection so that it does not trip ~~or cease injecting current~~ according to Requirement R1.
R2.	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~~ according to Requirement R2.
R3.	The Generator Owner or Transmission 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	The Generator Owner or Transmission 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	The Generator Owner or Transmission 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	The Generator Owner or Transmission Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the 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.	OR The Generator Owner or Transmission Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4.	The Generator Owner or Transmission Owner provided its protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 90 calendar days but less than	The Generator Owner or Transmission Owner provided its protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 120 calendar days but less than or equal to 150	The Generator Owner or Transmission Owner failed to provide its protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner failed to provide protection settings within 150 calendar days of a written request.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		or equal to 120 calendar days of a written request.	calendar days of a written request.	

D. Regional Variances

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[8~~5~~] in accordance with PRC-024 Attachment 2A~~a~~, such that the applicable protection does not cause the ~~generating resource~~Facility to which it is applied to trip within the "no trip zone" ~~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".
- Applicable voltage protection may ~~The generating resource(s) are permitted to~~ be set to trip ~~or to cease injecting current~~ during a voltage excursion within a portion of ~~bounded by~~ the "no trip zone" of PRC-024 Attachment 2A~~a~~ 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~~a~~, then the Generator Owner or Transmission Owner may set its protection

[8] 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 synchronous generator(s), type 1 or type 2 wind resource(s), or synchronous condenser(s); or (ii) provide signals to trip the same Facilities.

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~~a~~ and notify, within 30 calendar days of its designation, each Generator Owner or Transmission Owner that owns facilities[9] 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.

[9] Facilities in the strategic power plants include facilities with synchronous generator(s) 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~~a~~.

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.

E. Associated Documents

Implementation Plan

~~E.~~A. ~~Associated Documents~~

~~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	February 6, 2020	Adopted by the NERC Board of Trustees	Standard revised in Project 2018-04
3	July 9, 2020	FERC Letter Order approved PRC-024-3. Docket No. RD20-7-000	
3	July 17,2020	October 1, 2022	Effective Date
4	August 2, 2024	Revisions made by the 2020-02 Drafting Team	Revision accounts for changes with PRC-029-1 as part of Milestone 2 of NERC's work plan to address FERC Order No. 901.

Attachment 1

(Frequency No Trip Boundaries by Interconnection[10])

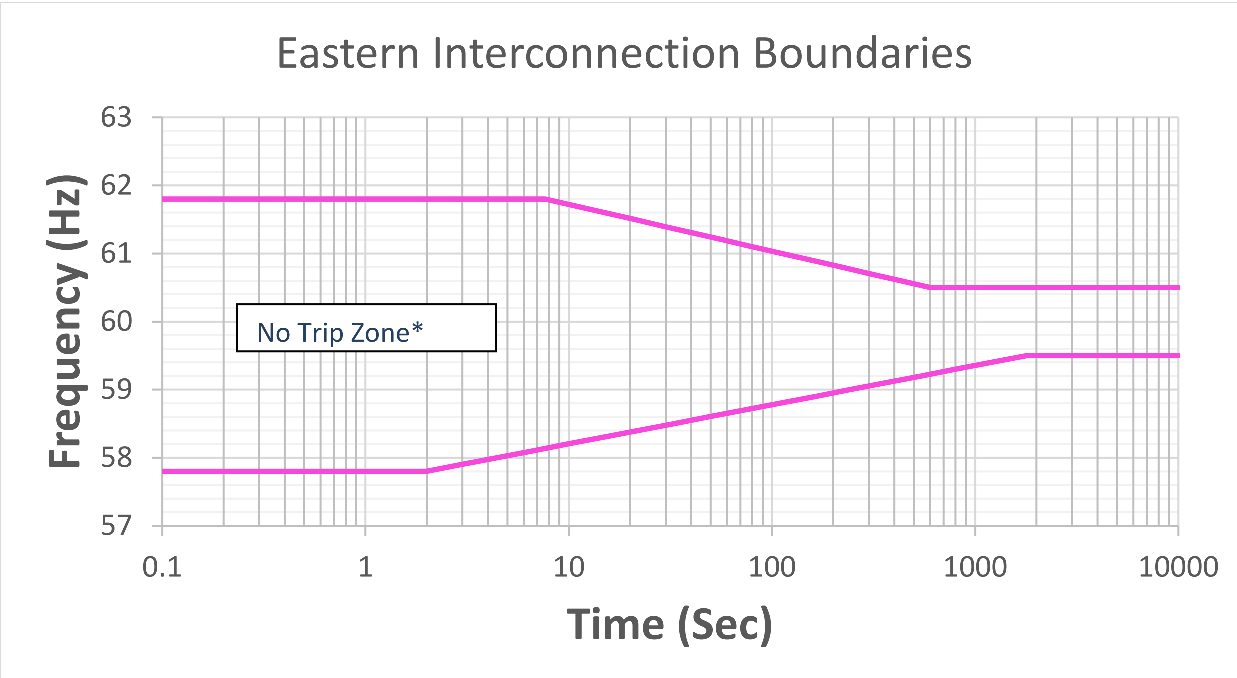

Figure 1: Eastern Interconnection Boundaries

~~*Figure 1*~~

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

Table 1: 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[11]	≤57.8	Instantaneous[11]
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$

[10] 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.

[11] 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.

<60.5	Continuous operation	> 59.5	Continuous operation

~~*Table 1*~~

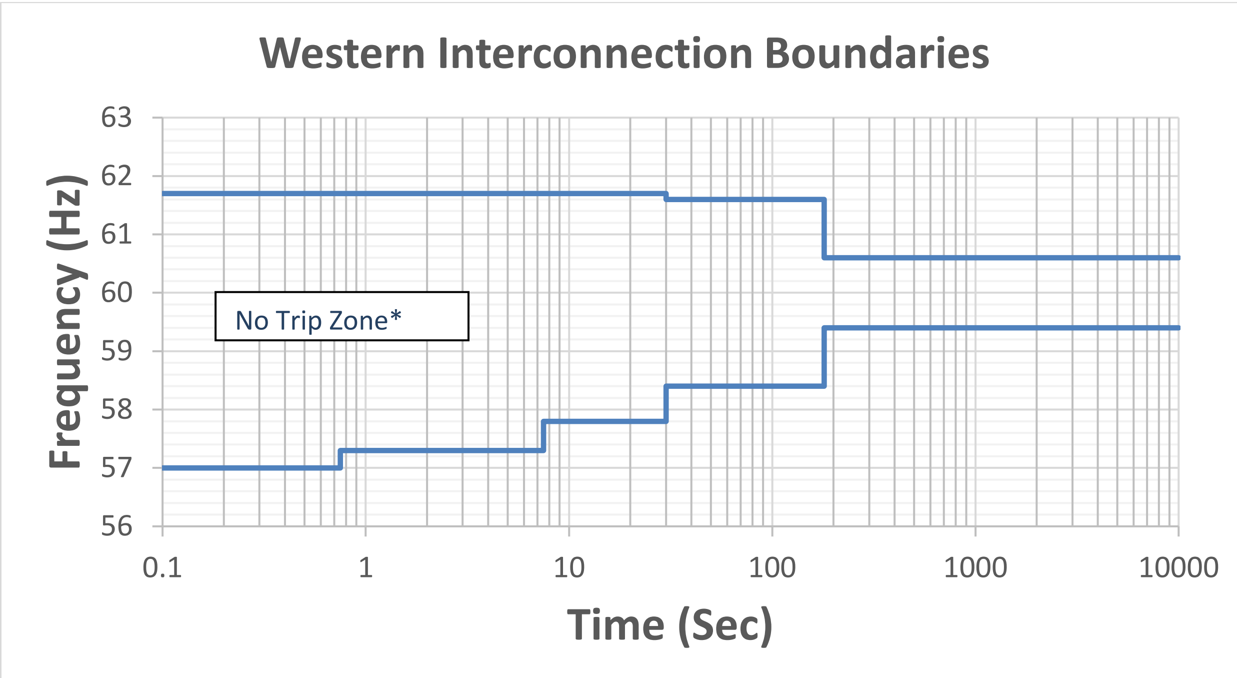

Figure 2: Western Interconnection Boundaries

~~*Figure 2*~~

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

Table 2: 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[11]	≤57.0	Instantaneous[11]
≥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*~~

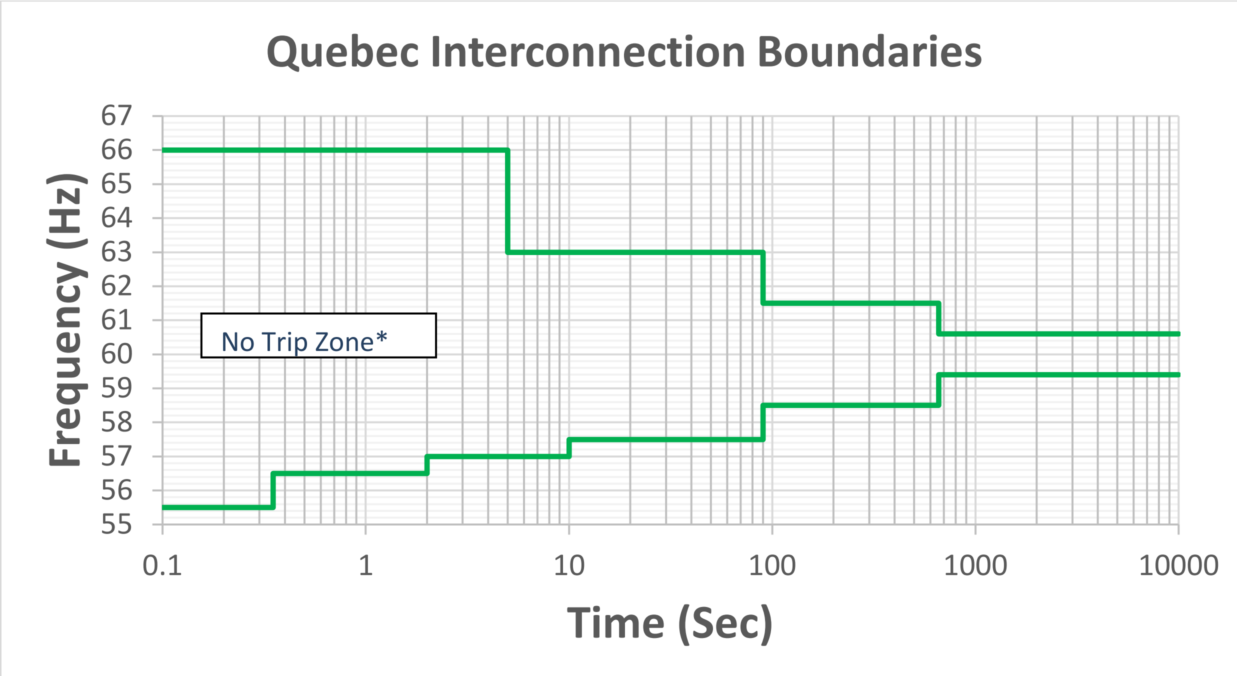

Figure 3: Quebec Interconnection Boundaries

~~*Figure 3*~~

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

Table 3: 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[11]	<55.5	Instantaneous[11]
≥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*~~

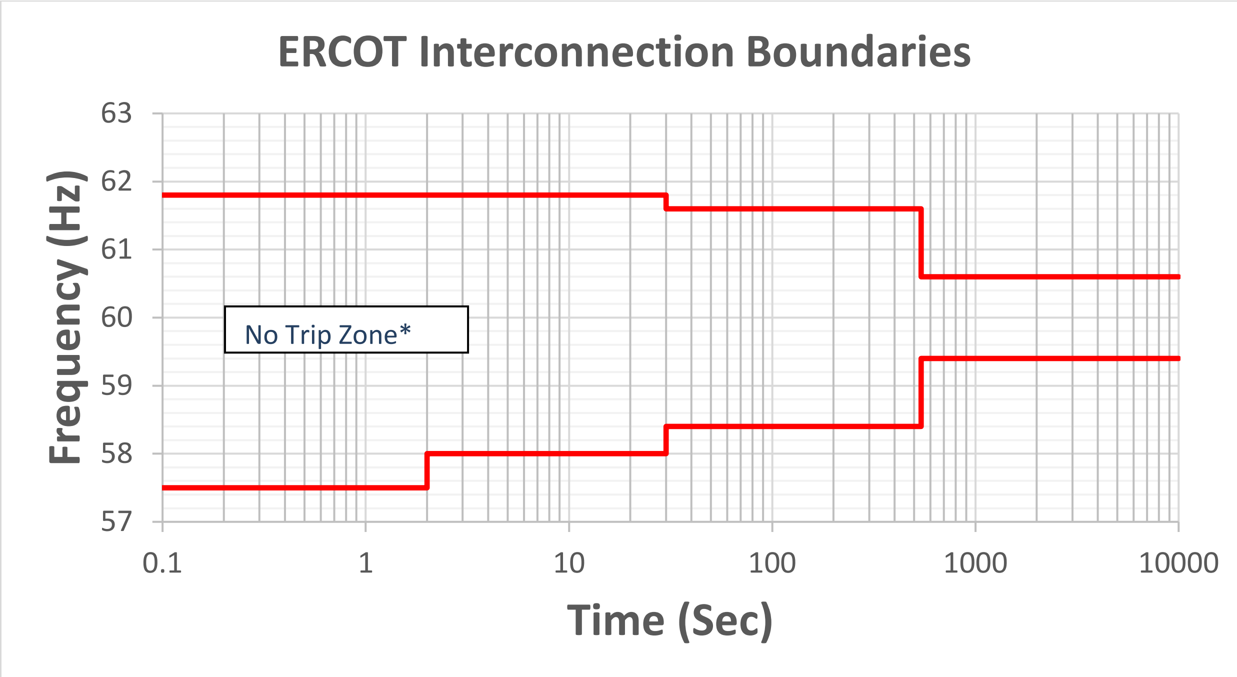

Figure 4: ERCOT Interconnection Boundaries

~~Figure 4~~

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

Table 4: 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[11]	≤57.5	Instantaneous[11]
≥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
(Voltage No-Trip Boundaries – Eastern, Western, and ERCOT Interconnections)

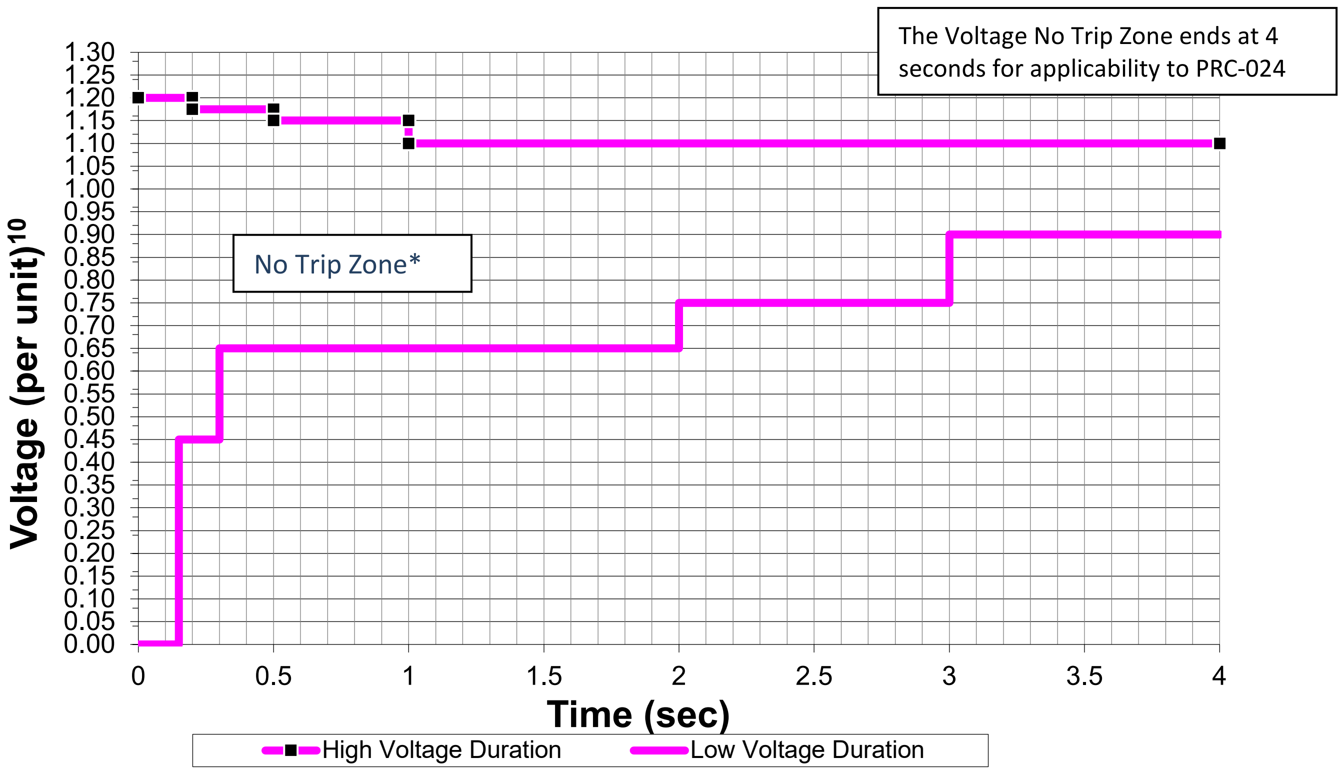

Figure 5: Voltage No-Trip Boundaries – Eastern, Western, and ERCOT Interconnections

~~[12]*Figure 1*~~

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

Table 5: 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

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

~~Table 1~~

Attachment 2: Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections

Boundary Details:

1. Unless otherwise specified by the Transmission Planner, the per unit voltage base for these boundaries is the nominal transmission system voltage (e.g., 100 kV, 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 400 kV, 500 kV, 765 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 boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase per unit voltage.
5. For applicability to PRC-024, the "no trip zone" ends at 4 seconds.

Evaluating Protection Settings:

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 conditions when evaluating protection settings:

a. The most probable real and reactive loading conditions for the synchronous generator, type 1 or 2 wind resources, or synchronous condenser ~~unit~~ under study.

b. All installed wind resource ~~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 or the collector station and the high side of the GSU/MPT.

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

PRC-024— Attachment 2a

(Voltage No-Trip Boundaries – Quebec Interconnection)

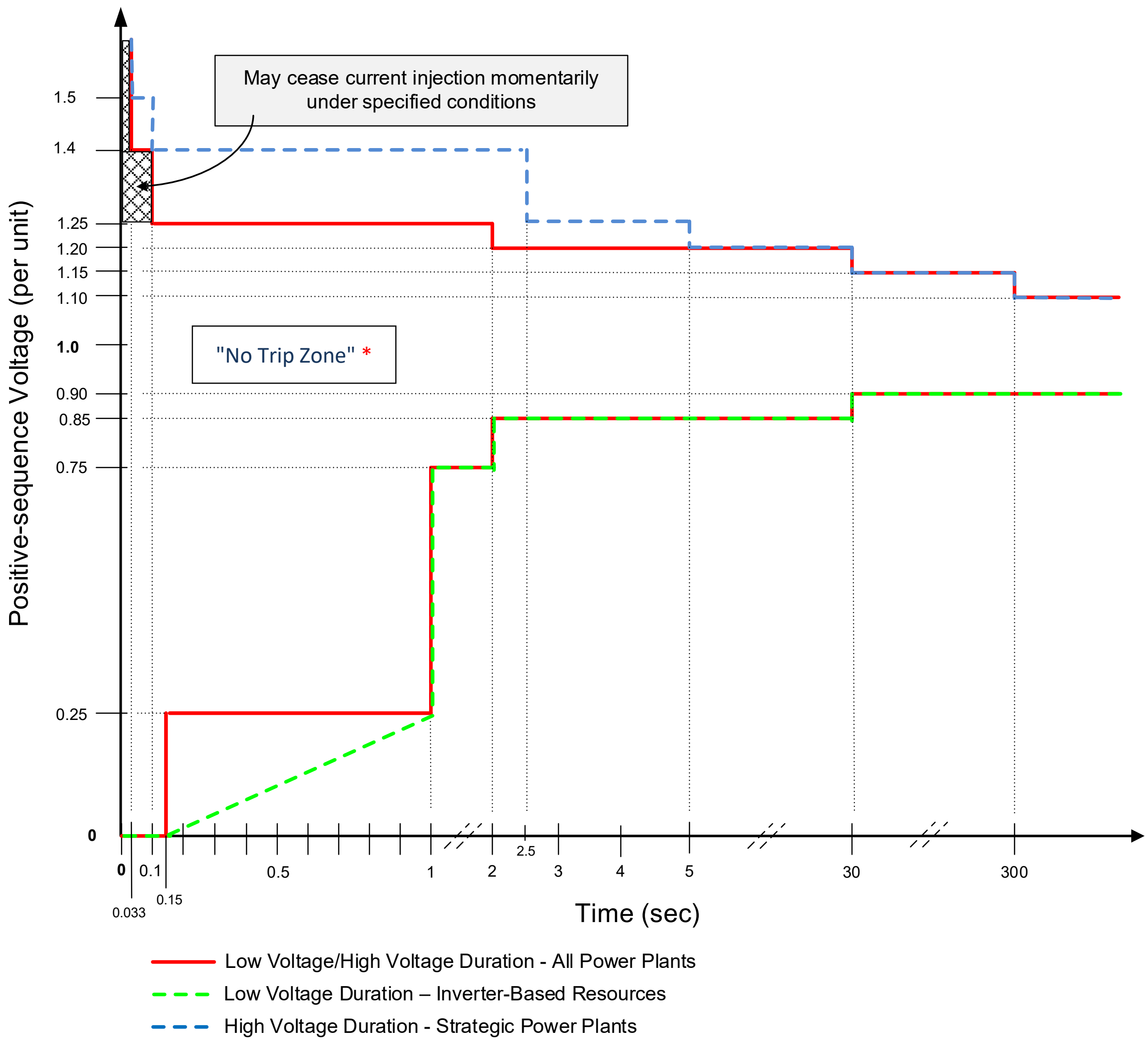

Figure 6: Voltage No-Trip Boundaries – Quebec Interconnection

~~***Figure 1***~~

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

~~1~~Table 6: High 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*~~

Table 7: Low 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 2~~a~~A: 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.

Technical Rationale

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

PRC-024-4 – Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and 2 Wind Plants, and Synchronous Condensers

General Rationale

The drafting team proposes to modify PRC-024-3 to retain the Reliability Standard as a protection-based standard with applicability to only synchronous generators, synchronous condensers, and type 1 and 2 wind plants. This proposal is a consequence of both the different natures of synchronous and inverter-based generation resources and several recent events exhibiting significant IBR ride-through deficiencies. The behavior of rotating synchronous generators during faults and other disturbances on the transmission system is well established and understood in comparison to IBR generation. The disturbance ride-through vulnerabilities of synchronous generators are pole slipping instability and undervoltage dropout of critical plant auxiliary equipment, leading to tripping of a generator. Pole slipping (or loss of synchronism) can be managed by active power dispatch constraints or stability System Operating Limits, and is outside the scope of Project 2020-02. Undervoltage dropout of critical auxiliary equipment is also outside the scope of Project 2020-02 because of complexities associated with auxiliary systems and how such equipment behaves under low voltage conditions. The Project 2020-02 Standard Authorization Request (SAR) notes that auxiliary equipment has not posed a ride-through risk and the SAR specifically excludes modifications in PRC-024-3 for auxiliary equipment.

Over-frequency protection, under-frequency protection, over-voltage protection, and under-voltage protection may or may not be applied to synchronous generating units. If applied, settings should be coordinated between the needs of generating unit protection and the no-trip zones within PRC-024-4 attachments. Coordination of generating unit capabilities, voltage regulating controls, and protection is addressed within PRC-019-2. Excitation and governing controls affect synchronous generator ride-through behavior to some degree but because of progressive improvement, standardization, and level of maturity of these controls, they are rarely a cause of unnecessary tripping during disturbances. In addition, there are other existing NERC standards to prevent unnecessary tripping of the generators during a system disturbance such as PRC-025-2 "Generator Relay Loadability" and PRC-026-2 "Relay Performance During Stable Power Swings". For these reasons, there is no need to impose actual disturbance ride-through requirements on synchronous units but only to include restrictions for frequency and voltage protection setting ranges as maintained in PRC-024-4.

Rationale for Applicability Section (4.0)

Functional Entities (4.1)

The functional entity responsible for setting frequency, voltage, and volts per hertz protection for synchronous generators, type 1 and 2 wind plants, and synchronous condensers is either the Generator Owner ~~(GO)~~ or Transmission Owner ~~(TO)~~. Planning Coordinators ~~(PC)~~ are retained as applicable entities only in the Quebec Interconnection. Modifications are proposed in PRC-024-4 to expand functional entity applicability to include "Transmission Owners that apply protection" because of the inclusion of synchronous condenser applicability in section 4.2.2.

Facilities (4.2)

Applicability Facilities subparts in Section 4.1.1 were modified to restrict PRC-024-4 to synchronous generators and type 1 and 2 wind plants. Section 4.2.2 was added to cover synchronous condensers and associated equipment.

Rationale for Requirements R1 through R4

Modifications were made to Requirements R1, R2, R3, and R4 to include the Transmission Owner as a functional entity applicable to each requirement because of the addition of synchronous condensers.

Modifications were made to Requirements R1, R2, R3, and R4 to include language for type 1 and 2 wind plants and synchronous condensers and to remove language that relates to inverter-based resource (IBR) functionality since IBRs will be addressed in a new standard PRC-029-1.

Violation Risk Factor and Violation Severity Level Justifications

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
PRC-024-4

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-024-4. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to BulkPower System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to BulkPower System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System. However, violation of a medium risk requirement is unlikely to lead to Bulk- Power System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BulkPower System, or the ability to effectively monitor, control, or restore the BulkPower System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

The VRF did not change from the previously FERC approved PRC-024-3 Reliability Standard.

VSLs for PRC-024-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to set its applicable frequency protection so that it does not trip according to Requirement R1.

VSL Justifications for PRC-024-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement adds a functional entity. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-024-4, Requirement R1	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

The VRF did not change from the previously FERC approved PRC-024-3 Reliability Standard.

VSLs for PRC-024-4, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
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 according to Requirement R2.

VSL Justifications for PRC-024-4, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement adds a functional entity. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-024-4, Requirement R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

The VRF did not change from the previously FERC approved PRC-024-3 Reliability Standard.

VSLs for PRC-024-4, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner or Transmission 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 or Transmission 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 or Transmission 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 or Transmission 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 or Transmission Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.

VSL Justifications for PRC-024-4, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement adds a functional entity. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for PRC-024-4, Requirement R3	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

The VRF did not change from the previously FERC approved PRC-024-3 Reliability Standard.

VSLs for PRC-024-4, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner or Transmission Owner provided its protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner or provided protection settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner or Transmission Owner failed to provide its protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner failed to provide protection settings within 150 calendar days of a written request.

VSL Justifications for PRC-024-4, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement adds a functional entity. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of	The proposed VSLs are binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-024-4, Requirement R4	
Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

Standards Announcement

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

Final Ballot Open through September 30, 2024

Now Available

A final ballot for **PRC-024-4 - Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and Type 2 Wind Resources, and Synchronous Condensers** is open through **8 p.m. Eastern, Monday, September 30, 2024.**

The Implementation Plan for Project 2020-02 Modifications to PRC-024 (Generator Ride-through) applies to both PRC-024-4 and PRC-029-1. The Implementation Plan was posted on September 17 with the re-ballot of PRC-029-1 and is open for final ballot through 8 p.m. Eastern, Monday, September 30, 2024.

Balloting

In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

Members of the ballot pool(s) associated with this project can log into the Standards Balloting and Commenting System (SBS) and submit votes here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The voting results will be posted and announced after the ballots close. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Director of Standards Development, Jamie Calderon (via email) or at 404-960-0568.

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Atlanta, GA 30326
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BALLOT RESULTS

Ballot Name: 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-024-4 FN 3 ST
Voting Start Date: 9/25/2024 11:12:13 AM
Voting End Date: 9/30/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 246
Total Ballot Pool: 271
Quorum: 90.77
Quorum Established Date: 9/25/2024 12:01:49 PM
Weighted Segment Value: 86.41

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	75	1	47	0.855	8	0.145	0	11	9
Segment: 2	8	0.8	7	0.7	1	0.1	0	0	0
Segment: 3	55	1	41	0.837	8	0.163	0	3	3
Segment: 4	14	1	11	0.917	1	0.083	0	0	2
Segment: 5	68	1	44	0.83	9	0.17	0	8	7
Segment: 6	46	1	29	0.806	7	0.194	0	6	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0
Segment: 9	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	5	0.5	5	0.5	0	0	0	0	0
Totals:	271	6.3	184	5.444	34	0.856	0	28	25

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		None	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner	Carly Miller	Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Negative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Negative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas	Jennifer Lapaix	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		Affirmative	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	George Pino		None	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	American Municipal Power	Amy Ritts		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Abstain	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Negative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson	David Campbell	Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Negative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Chance Back		Abstain	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	N/A
5	PSEG Nuclear LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Affirmative	N/A
5	Tennessee Valley Authority	Darren Boehm		Abstain	N/A
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	U.S. Bureau of Reclamation	Wendy Kalidass		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	Mathew Miller		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Abstain	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Great River Energy	Brian Meloy		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Negative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Russell Ferrell		Affirmative	N/A
6	Manitoba Hydro	Brandin Stoesz		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Abstain	N/A
6	New York Power Authority	Shelly Dineen		Negative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer	Dane Rogers	Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Robert Witham		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Abstain	N/A
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Affirmative	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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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

Final Draft of PRC-029-1 is posted for a formal comment and additional ballot.

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023
25-day formal comment period and initial ballot	March 27 – April 22, 2024
15-day formal comment period and additional ballot	June 18 – July 8, 2024
15-day formal comment period and additional ballot	July 22 – August 12, 2024
14-day formal comment period and additional ballot	September 17 – September 30, 2024
Final Ballot	None Required
Board adoption	October 8, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Ride-through: The plant/facility remains connected and continues to operate through voltage or frequency system disturbances.

A. Introduction

1. **Title:** **Frequency and Voltage Ride-through Requirements for Inverter-based Resources**

2. **Number:** **PRC-029-1**

3. **Purpose:** To ensure that IBRs Ride-through to support the Bulk Power System (BPS) during and after defined frequency and voltage excursions.

4. **Applicability:**

   4.1 Functional Entities:

   4.1.1. Generator Owner

   4.2 Facilities:

   4.2.1. Bulk Electric System (BES) IBRs

   4.2.2. Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Effective Date: See Implementation Plan for Project 2020-02 – PRC-029-1

Standard-only Definition: None

B. Requirements and Measures

R1. Each Generator Owner shall ensure the design and operation is such that each IBR meets or exceeds Ride-through requirements, in accordance with the "must Ride-through[1] zone" as specified in Attachment 1, except in the following conditions: *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

- The IBR needed to electrically disconnect in order to clear a fault;
- The voltage at the high-side of the main power transformer[2] went outside an accepted hardware limitation, in accordance with Requirement R4;
- The instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer and is initiated by a non-fault switching event on the transmission system[3]; or
- The Volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

M1. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to Ride-through requirements, as specified in Requirement R1. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) to demonstrate that the operation of each IBR did adhere to Ride-through requirements, as specified in Requirement R1. If the Generator Owner choose to utilize Ride-through exemptions that occur within the "must Ride-through zone" and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) data to demonstrate that the IBR failed to Ride-through during a phase jump of greater than or equal to 25 electrical degrees, and documentation from their Transmission Planner, Reliability Coordinator, Planning Coordinator, or Transmission Operator that a non-fault initiated switching event occurred.

R2. Each Generator Owner shall ensure the design and operation is such that the voltage performance for each IBR adheres to the following during a voltage excursion, unless a documented hardware limitation exists in accordance with Requirement R4. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

2.1. While the voltage at the high-side of the main power transformer remains within the continuous operation region as specified in Attachment 1, each IBR shall:

[1] Includes no tripping associated with phase lock loop loss of synchronism.

[2] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for IBRs. In case of IBR connecting via a dedicated Voltage Source Converter High Voltage Direct Current (VSC-HVDC), the main power transformer is the main power transformer on the receiving end.

[3] Current blocking mode may be used for non-fault initiated phase jumps greater than 25 degrees in order to prevent tripping.

2.1.1 Continue to deliver the pre-disturbance level of Real Power or available Real Power[4], whichever is less.[5]

2.1.2 Continue to deliver Reactive Rower up to its Reactive Power limit and according to its controller settings.

2.1.3 Prioritize Real Power or Reactive Power when the voltage is less than 0.95 per unit, the voltage is within the continuous operating region, and the IBR cannot deliver both Real Power and Reactive Power due to a current limit or Reactive Power limit, unless otherwise specified through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.2. While voltage at the high-side of the main power transformer is within the mandatory operation region as specified in Attachment 1, each IBR shall exchange current, up to the maximum capability to provide voltage support, on the affected phases during both symmetrical and asymmetrical voltage disturbances, either under[6]:

- Reactive Power priority by default; or
- Real Power priority if required through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.3. While voltage at the high-side of the main power transformer is within the permissive operation region, as specified in Attachment 1, each IBR may operate in current blocking mode if necessary to avoid tripping. Otherwise, each IBR shall follow the requirements for the mandatory operation region in Requirement R2.2.

2.3.1 If an IBR enters current blocking mode, it shall restart current exchange in less than or equal to five cycles of positive sequence voltage returning to a continuous operation region or mandatory operation region.

2.4. Each IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable high voltage thresholds and time durations in its response as voltage recovers from the mandatory or permissive operation regions to the continuous operation region.

2.5. Each IBR shall restore Real Power output to the pre-disturbance or available level[7] (whichever is lesser) within 1.0 second when the voltage at the high-side of the main power transformer returns from the mandatory operation region or

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[4] "Available Real Power" refers to changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes of facility Real Power attributed to IBR tripping in whole or part.

[5] Except if this would occur during a frequency excursion. The Real Power response should recover in accordance with the primary frequency controller.

[6] In either case and if required, the magnitude of Real Power and reactive current shall be as specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

[7] "Available Real Power" refers to changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes of facility Real Power attributed to IBR tripping in whole or part.

permissive operation region (including operating in current blocking mode) to the continuous operation region, as specified in Attachment 1, unless an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires a lower post-disturbance Real Power level requirement or requires a different post-disturbance Real Power restoration time through other mechanisms.[8]

M2. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to requirements, as specified in Requirement R2. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) data to demonstrate that the operation of each IBR did adhere to performance requirements, as specified in Requirement R2, during each voltage excursion measured at the high-side of the main power transformer. Regarding R2.1.3, R2.2, and R2.5, the Generator Owner shall retain evidence of receiving such performance requirements, (e.g., email exchange, contract information) if the Transmission Planner, Transmission Operator, Reliability Coordinator, or Planning Coordinator has required the Generator Owner through other mechanisms to follow performance requirements other than those in Requirement R2 (e.g., ramp rates, Reactive Power prioritization).

R3. Each Generator Owner shall ensure the design and operation is such that each IBR meets or exceeds Ride-through requirements during a frequency excursion event whereby the System frequency remains within the "must Ride-through zone" according to Attachment 2 and the absolute rate of change of frequency (RoCoF)[9] magnitude is less than or equal to 5 Hz/second, unless a documented hardware limitation exists in accordance with Requirement R4. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

M3. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to Ride-through requirements, as specified in Requirement R3. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) data to demonstrate the operation of each IBR did adhere to Ride-through requirements, as specified in Requirement R3, during each frequency excursion event measured at the high-side of the main power transformer.

R4. Each Generator Owner identifying an IBR that is in-service by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1-R3, and requires an exemption from specific

[8] Except if this would occur during a frequency excursion. The Real Power response should recover in accordance with the primary frequency controller.

[9] Rate of change of frequency (RoCoF) is calculated as the average rate of change for multiple calculated system frequencies for a time period of greater than or equal to 0.1 second. RoCoF is not calculated during the fault occurrence and clearance.

Ride-through criteria shall:[10] *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1. This documentation shall include:

4.1.1 Identifying information of the IBR (name and facility number);

4.1.2 Which aspects of Ride-through requirements that the IBR would be unable to meet and the capability of the hardware due to the limitation;

4.1.3 Identification of the specific piece(s) of hardware causing the limitation;

4.1.4 Technical documentation verifying the limitation is due to hardware that would need to be physically replaced to meet all Ride-through criteria, and that the limitation cannot be remedied by software updates or setting changes; and

4.1.5 Information regarding any plans to remedy the hardware limitation (such as an estimated date).

4.2. Provide a copy of the information detailed in Requirement R4.1, except for any material considered by the original equipment manufacturer to be proprietary information, to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the Compliance Enforcement Authority (CEA) no later than 12 months following the effective date of PRC-029-1.[11]

4.2.1 Provide any response for additional information requested by the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA to the requestor within 90 days of the request.

4.2.2 Provide a copy of the acceptance of a hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of receiving the acceptance.[12]

4.3. Each Generator Owner with a previously accepted limitation that replaces the hardware causing the limitation shall document and communicate such a hardware change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the hardware change.

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[10] The exemption requests for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

[11] To the extent the original equipment manufacturer considers any material to be proprietary, the Generator Owner is required to share this proprietary material only with the CEA.

[12] Acceptance by the CEA is verification that the information provided includes all information listed in Requirement R4.1.

4.3.1 When existing hardware causing the limitation is replaced, the exemption for that Ride-through criteria no longer applies.

M4. Each Generator Owner submitting for an exemption for an IBR that is in-service by the effective date of PRC-029-1, shall have evidence of submission to the CEA consistent with the information listed in Requirement R4.1. Each Generator Owner shall have evidence of communicated copies of each submission in accordance with Requirement R4.2 and to the associated entities described in Requirement R4.2. Acceptable types of evidence for submittals include, but are not limited to, meeting minutes, agreements, copies of procedures or protocols in effect, or email correspondence. Acceptable types of evidence for a hardware limitation may include, but is not limited to damage curves provided by the original equipment manufacturer. Each Generator Owner that receives a request for additional information under Requirement R4.2.1 shall have evidence of providing that information within 90 days. Each Generator Owner that replaces hardware at an IBR that is directly associated with an accepted exemption and that hardware is the cause for the limitation, shall have evidence of communicating the hardware change to the associated entities described in Requirement R4.3 within 90 days of the hardware replacement.

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.

   1.2. Evidence Retention: 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.

   - Each Generator Owner shall retain evidence with Requirements R1, R2, and R3 in this standard for 36 calendar months or the date of the last audit, whichever is greater.
   - Each Generator Owner shall retain evidence with Requirement R4 in this standard for five calendar years or the date of the last audit, whichever is greater.

   1.3. Compliance Monitoring and Enforcement 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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The Generator Owner failed to ensure the design capability of each applicable IBR to Ride-through in accordance with Attachment 1, except for those conditions identified in Requirement R1.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to Ride-through requirements in accordance with Attachment 1, except for those conditions identified in Requirement R1.
R2.	The Generator Owner failed to ensure the design capability of each applicable IBR to adhere to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.
R3.	The Generator Owner failed to ensure the design capability of each applicable IBR to Ride-through in accordance with Attachment 2, unless a documented hardware limitation exists in accordance with Requirement R4.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to Ride-through requirements in accordance with Attachment 2, unless a documented hardware limitation exists in accordance with Requirement R4.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 12 months, but less than or equal to 15 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 90 days but less than or equal to 120 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 90 days but less than or equal to 120 days after receiving the acceptance of a hardware limitation by the CEA. OR	The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 15 months, but less than or equal to 18 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 120 days, but less than or equal to 150 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 120 days but less than or equal to 150 days after receiving the acceptance of a hardware limitation by the CEA.	The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 18 months, but less than or equal to 24 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 150 days but less than or equal to 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 150 days but less than or equal to 180 days after receiving the acceptance of a hardware limitation by the CEA. OR	The Generator Owner failed to document complete information for IBR identified with known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1, R2, or R3. OR The Generator Owner failed to provide a copy to the applicable entities as detailed in Requirement R4.2 within 24 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and CEA more than 90 calendar days but less than or equal to 120 calendar days after the change to the hardware.	OR The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 120 calendar days but less than or equal to 150 calendar days after the change to the hardware.	The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 150 calendar days but less than or equal to 180 calendar days after the change to the hardware.	entities as detailed in Requirement R4.2.2 more than 180 days after receiving the acceptance of a hardware limitation by the CEA. The Generator Owner with a previously communicated hardware limitation that replace the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s),Reliability Coordinator(s), and CEA more than 180 days after the change to the hardware.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan .

Version History

Version	Date	Action	Change Tracking
1	10/8/24	Draft 4 approved by the NERC Board of Trustees	
1	10/16/24	Draft4_Errata approved by the Standards Committee	

Attachment 1: Voltage Ride-Through Criteria

Table 1: Voltage Ride-through Requirements for AC-Connected Wind IBR [13]

Voltage (per unit)[14]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[15]	N/A
≥ 1.10	Mandatory Operation Region	1.0
> 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90	Mandatory Operation Region	3.00
< 0.70	Mandatory Operation Region	2.50
< 0.50	Mandatory Operation Region	1.20
< 0.25	Mandatory Operation Region	0.16
< 0.10	Permissive Operation Region	0.16

Table 2: Voltage Ride-through Requirements for All Other IBR

Voltage (per unit)[16]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[17]	N/A
> 1.10	Mandatory Operation Region	1.0
> 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90	Mandatory Operation Region	6.00
< 0.70	Mandatory Operation Region	3.00
< 0.50	Mandatory Operation Region	1.20
< 0.25	Mandatory Operation Region	0.32
< 0.10	Permissive Operation Region	0.32

[13] Type 3 and type 4 wind resources directly connected to the AC Transmission System.
[14] Refer to bullet #4 below.
[15] These conditions are referred to as the "may Ride-through zone".
[16] Refer to bullet #4 below.
[17] These conditions are referred to as the "may Ride-through zone".

1. Table 1 applies to type 3 and type 4 wind IBR or hybrid IBR that include wind, unless connected via a dedicated Voltage Source Converter - High Voltage Direct Current (VSC-HVDC) transmission facility.
2. Table 2 applies to all other IBR types not covered in Table 1; including, but not limited to, the following facilities:
    a. IBR, regardless of their energy resource, interconnecting via a dedicated VSC-HVDC transmission facility.
    b. Other IBR or hybrid IBR consisting of photovoltaic (PV) and BESS.
3. The applicable voltage for VSC-HVDC system with a dedicated connection to an IBR is on the AC side of the transformer(s) that is (are) used to connect the VSC-HVDC system to the interconnected transmission system.
4. The voltage base for per unit calculation is the nominal phase-to-ground or phase-to-phase transmission system voltage unless otherwise defined by the Planning Coordinator, Transmission Planner, or Transmission Owner.
5. The applicable voltage for Tables 1 and 2 is identified as the voltage max/min of phase-to-neutral or phase-to-phase fundamental root mean square (RMS) voltage at the high-side of the main power transformer.
6. Tables 1 and 2 are only applicable when the frequency is within the "must Ride-through zone" as specified in Figure 1 of Attachment 2.
7. At any given voltage value, each IBR shall Ride-through unless the time duration at that voltage has exceeded the specified minimum Ride-through time duration. If the voltage is continuously varying over time, it is necessary to add the duration within each band of Tables 1 and 2 over any 10 second time period.
8. The specified duration of the mandatory operation regions and the permissive operation regions in Tables 1 and 2 is cumulative over one or more disturbances within any 10 second time period.
9. The IBR may trip for more than four deviations of the applicable voltage at the high-side of the main power transformer outside of the continuous operation region within any 10 second time period.
10. Instantaneous trip settings based on instantaneously calculated voltage measurements with less than filtering lengths of one cycle (16.6 millisecond) are not permissible.
11. The "must Ride-through zone" is the combined area of the mandatory operating regions, the continuous operating regions, and the permissive operating region. All area outside of these operating regions is referred to as the "may Ride-through zone".

Attachment 2: Frequency Ride-Through Criteria

Table 3: Frequency Ride-through Capability Requirements

System Frequency (Hz)	Minimum Ride-Through Time (sec)
> 61.8	May trip
> 61.2	299
≤ 61.2 and ≥ 58.8	Continuous
< 58.8	299
< 57.0	May trip

1. Frequency measurements are taken at the high-side of the main power transformer.
2. Frequency is measured over a period of time (typically 3-6 cycles) to calculate system frequency at the high-side of the main power transformer.
3. Instantaneous or single points of measurement may not be used in the determination of control settings.
4. At any given frequency value, each IBR shall Ride-through unless the time duration at that frequency has exceeded the specified minimum ride-through time duration.
5. The specified durations of Table 3 are cumulative over one or more disturbances within a 10-minute time period.

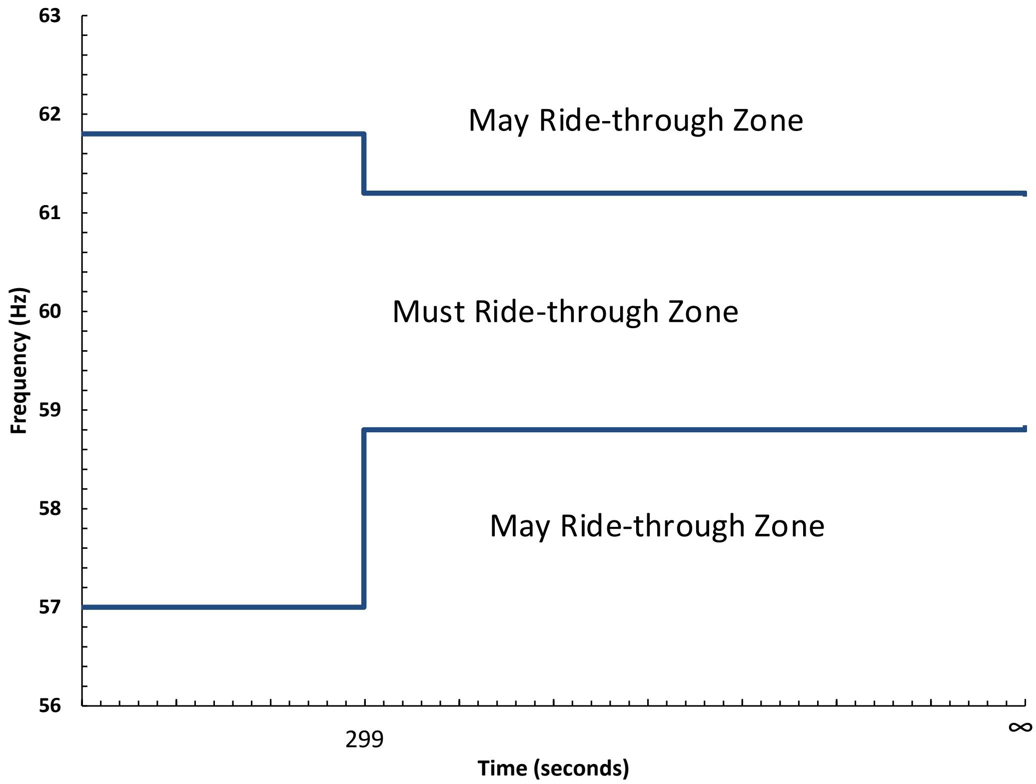

Figure 1: PRC-029 Frequency Ride-through Requirements

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

Draft 4 of PRC-029-1 is posted for a formal comment and additional ballot.

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023
25-day formal comment period and initial ballot	March 27 – April 22, 2024
15-day formal comment period and additional ballot	June 18 – July 8, 2024
15-day formal comment period and additional ballot	July 22 – August 12, 2024

Anticipated Actions	Date
14-day formal comment period and additional ballot	September 17 – September 30, 2024
Final Ballot	None Required
Board adoption	October 8, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Ride-through: The plant/facility remains connected and continues to operate through voltage or frequency system disturbances.

A. Introduction

1. **Title:** **Frequency and Voltage Ride-through Requirements for Inverter-based Resources**
2. **Number:** **PRC-029-1**
3. **Purpose:** To ensure that IBRs Ride-through to support the Bulk Power System (BPS) during and after defined frequency and voltage excursions.
4. **Applicability:**

   4.1 Functional Entities:

   4.1.1. Generator Owner

   4.2 Facilities:

   4.2.1. Bulk Electric System (BES) IBRs

   4.2.2. Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Effective Date: See Implementation Plan for Project 2020-02 – PRC-029-1

Standard-only Definition: None

B. Requirements and Measures

R1. Each Generator Owner shall ensure the design and operation is such that each IBR meets or exceeds Ride-through requirements, in accordance with the "must Ride-through[1] zone" as specified in Attachment 1, except in the following conditions: *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

- The IBR needed to electrically disconnect in order to clear a fault;
- The voltage at the high-side of the main power transformer[2] went outside an accepted hardware limitation, in accordance with Requirement R4;
- The instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer and is initiated by a non-fault switching event on the transmission system[3]; or
- The Volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

M1. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to Ride-through requirements, as specified in Requirement R1. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) to demonstrate that the operation of each IBR did adhere to Ride-through requirements, as specified in Requirement R1. If the Generator Owner choose to utilize Ride-through exemptions that occur within the "must Ride-through zone" and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) data to demonstrate that the IBR failed to Ride-through during a phase jump of greater than or equal to 25 electrical degrees, and documentation from their Transmission Planner, Reliability Coordinator, Planning Coordinator, or Transmission Operator that a non-fault initiated switching event occurred.

R2. Each Generator Owner shall ensure the design and operation is such that the voltage performance for each IBR adheres to the following during a voltage excursion, unless a documented hardware limitation exists in accordance with Requirement R4. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

2.1. While the voltage at the high-side of the main power transformer remains within the continuous operation region as specified in Attachment 1, each IBR shall:

[1] Includes no tripping associated with phase lock loop loss of synchronism.

[2] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for IBRs. In case of IBR connecting via a dedicated Voltage Source Converter High Voltage Direct Current (VSC-HVDC), the main power transformer is the main power transformer on the receiving end.

[3] Current blocking mode may be used for non-fault initiated phase jumps greater than 25 degrees in order to prevent tripping.

2.1.1 Continue to deliver the pre-disturbance level of Real Power or available Real Power[4], whichever is less.[5]

2.1.2 Continue to deliver Reactive Rower up to its Reactive Power limit and according to its controller settings.

2.1.3 Prioritize Real Power or Reactive Power when the voltage is less than 0.95 per unit, the voltage is within the continuous operating region, and the IBR cannot deliver both Real Power and Reactive Power due to a current limit or Reactive Power limit, unless otherwise specified through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.2. While voltage at the high-side of the main power transformer is within the mandatory operation region as specified in Attachment 1, each IBR shall exchange current, up to the maximum capability to provide voltage support, on the affected phases during both symmetrical and asymmetrical voltage disturbances, either under[6]:

- Reactive Power priority by default; or
- Real Power priority if required through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.3. While voltage at the high-side of the main power transformer is within the permissive operation region, as specified in Attachment 1, each IBR may operate in current blocking mode if necessary to avoid tripping. Otherwise, each IBR shall follow the requirements for the mandatory operation region in Requirement R2.2.

2.3.1 If an IBR enters current blocking mode, it shall restart current exchange in less than or equal to five cycles of positive sequence voltage returning to a continuous operation region or mandatory operation region.

2.4. Each IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable high voltage thresholds and time durations in its response as voltage recovers from the mandatory or permissive operation regions to the continuous operation region.

2.5. Each IBR shall restore Real Power output to the pre-disturbance or available level[7] (whichever is lesser) within 1.0 second when the voltage at the high-side of the main power transformer returns from the mandatory operation region or

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[4] “Available Real Power" refers to changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes of facility Real Power attributed to IBR tripping in whole or part.
[5] Except if this would occur during a frequency excursion. The Real Power response should recover in accordance with the primary frequency controller.
[6] In either case and if required, the magnitude of Real Power and reactive current shall be as specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.
[7] “Available Real Power" refers to changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes of facility Real Power attributed to IBR tripping in whole or part.

permissive operation region (including operating in current blocking mode) to the continuous operation region, as specified in Attachment 1, unless an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires a lower post-disturbance Real Power level requirement or requires a different post-disturbance Real Power restoration time through other mechanisms.[8]

M2. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to requirements, as specified in Requirement R2. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) data to demonstrate that the operation of each IBR did adhere to performance requirements, as specified in Requirement R2, during each voltage excursion measured at the high-side of the main power transformer. Regarding R2.1.3, R2.2, and R2.5, the Generator Owner shall retain evidence of receiving such performance requirements, (e.g., email exchange, contract information) if the Transmission Planner, Transmission Operator, Reliability Coordinator, or Planning Coordinator has required the Generator Owner through other mechanisms to follow performance requirements other than those in Requirement R2 (e.g., ramp rates, Reactive Power prioritization).

R3. Each Generator Owner shall ensure the design and operation is such that each IBR meets or exceeds Ride-through requirements during a frequency excursion event whereby the System frequency remains within the “must Ride-through zone” according to Attachment 2 and the absolute rate of change of frequency (RoCoF)[9] magnitude is less than or equal to 5 Hz/second, unless a documented hardware limitation exists in accordance with Requirement R4. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

M3. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to Ride-through requirements, as specified in Requirement R3. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) data to demonstrate the operation of each IBR did adhere to Ride-through requirements, as specified in Requirement R3, during each frequency excursion event measured at the high-side of the main power transformer.

R4. Each Generator Owner identifying an IBR that is in-service by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1-R3, and requires an exemption from specific

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[8] Except if this would occur during a frequency excursion. The Real Power response should recover in accordance with the primary frequency controller.

[9] Rate of change of frequency (RoCoF) is calculated as the average rate of change for multiple calculated system frequencies for a time period of greater than or equal to 0.1 second. RoCoF is not calculated during the fault occurrence and clearance.

Ride-through criteria shall:[10] *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1. This documentation shall include:

4.1.1 Identifying information of the IBR (name and facility number);

4.1.2 Which aspects of Ride-through requirements that the IBR would be unable to meet and the capability of the hardware due to the limitation;

4.1.3 Identification of the specific piece(s) of hardware causing the limitation;

4.1.4 Technical documentation verifying the limitation is due to hardware that would need to be physically replaced to meet all Ride-through criteria, and that the limitation cannot be remedied by software updates or setting changes; and

4.1.5 Information regarding any plans to remedy the hardware limitation (such as an estimated date).

4.2. Provide a copy of the information detailed in Requirement R4.1, except for any material considered by the original equipment manufacturer to be proprietary information, to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the Compliance Enforcement Authority (CEA) no later than 12 months following the effective date of PRC-029-1.[11]

4.2.1 Provide any response for additional information requested by the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA to the requestor within 90 days of the request.

4.2.2 Provide a copy of the acceptance of a hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of receiving the acceptance.[12]

4.3. Each Generator Owner with a previously accepted limitation that replaces the hardware causing the limitation shall document and communicate such a hardware change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the hardware change.

[10] The exemption requests for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
[11] To the extent the original equipment manufacturer considers any material to be proprietary, the Generator Owner is required to share this proprietary material only with the CEA.
[12] Acceptance by the CEA is verification that the information provided includes all information listed in Requirement R4.1.

4.3.1 When existing hardware causing the limitation is replaced, the exemption for that Ride-through criteria no longer applies.

M4. Each Generator Owner submitting for an exemption for an IBR that is in-service by the effective date of PRC-029-1, shall have evidence of submission to the CEA consistent with the information listed in Requirement R4.1. Each Generator Owner shall have evidence of communicated copies of each submission in accordance with Requirement R4.2 and to the associated entities described in Requirement R4.2. Acceptable types of evidence for submittals include, but are not limited to, meeting minutes, agreements, copies of procedures or protocols in effect, or email correspondence. Acceptable types of evidence for a hardware limitation may include, but is not limited to damage curves provided by the original equipment manufacturer. Each Generator Owner that receives a request for additional information under Requirement R4.2.1 shall have evidence of providing that information within 90 days. Each Generator Owner that replaces hardware at an IBR that is directly associated with an accepted exemption and that hardware is the cause for the limitation, shall have evidence of communicating the hardware change to the associated entities described in Requirement R4.3 within 90 days of the hardware replacement.

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.

   1.2. **Evidence Retention:** 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.

   - Each Generator Owner shall retain evidence with Requirements R1, R2, and R3 in this standard for 36 calendar months or the date of the last audit, whichever is greater.
   - Each Generator Owner shall retain evidence with Requirement R4 in this standard for five calendar years or the date of the last audit, whichever is greater.

   1.3. **Compliance Monitoring and Enforcement 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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Owner failed to ensure the design capability of each applicable IBR to Ride-through in accordance with Attachment 1, except for those conditions identified in Requirement R1.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to Ride-through requirements in accordance with Attachment 1, except for those conditions identified in Requirement R1.
R2.	The Generator Owner failed to ensure the design capability of each applicable IBR to adhere to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.
R3.	The Generator Owner failed to ensure the design capability of each applicable IBR to Ride-through in accordance with Attachment 2, unless a documented hardware limitation exists in accordance with Requirement R4.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to Ride-through requirements in accordance with Attachment 2, unless a documented hardware limitation exists in accordance with Requirement R4.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 12 months, but less than or equal to 15 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 90 days but less than or equal to 120 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 90 days but less than or equal to 120 days after receiving the acceptance of a hardware limitation by the CEA. OR	The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 15 months, but less than or equal to 18 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 120 days, but less than or equal to 150 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 120 days but less than or equal to 150 days after receiving the acceptance of a hardware limitation by the CEA.	The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 18 months, but less than or equal to 24 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 150 days but less than or equal to 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 150 days but less than or equal to 180 days after receiving the acceptance of a hardware limitation by the CEA. OR	The Generator Owner failed to document complete information for IBR identified with known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1, R2, or R3. OR The Generator Owner failed to provide a copy to the applicable entities as detailed in Requirement R4.2 within 24 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and CEA more than 90 calendar days but less than or equal to 120 calendar days after the change to the hardware.	OR The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 120 calendar days but less than or equal to 150 calendar days after the change to the hardware.	The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 150 calendar days but less than or equal to 180 calendar days after the change to the hardware.	entities as detailed in Requirement R4.2.2 more than 180 days after receiving the acceptance of a hardware limitation by the CEA. The Generator Owner with a previously communicated hardware limitation that replace the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s),Reliability Coordinator(s), and CEA more than 180 days after the change to the hardware.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan .

Version History

Version	Date	Action	Change Tracking
Initial Draft	3/27/24	Draft	
Draft 2	6/4/24	Revised following initial comment review	
Draft 3	7/22/24	Revised following additional comment review	
Draft 4	9/12/24	Revised following additional comment review	

Attachment 1: Voltage Ride-Through Criteria

Table 1: Voltage Ride-through Requirements for AC-Connected Wind IBR [13]

Voltage (per unit)[14]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[15]	N/A
≥ 1.10	Mandatory Operation Region	1.0
> 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90	Mandatory Operation Region	3.00
< 0.70	Mandatory Operation Region	2.50
< 0.50	Mandatory Operation Region	1.20
< 0.25	Mandatory Operation Region	0.16
< 0.10	Permissive Operation Region	0.16

Table 2: Voltage Ride-through Requirements for All Other IBR

Voltage (per unit)[16]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[17]	N/A
> 1.10	Mandatory Operation Region	1.0
> 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90	Mandatory Operation Region	6.00
< 0.70	Mandatory Operation Region	3.00
< 0.50	Mandatory Operation Region	1.20
< 0.25	Mandatory Operation Region	0.32
< 0.10	Permissive Operation Region	0.32

[13] Type 3 and type 4 wind resources directly connected to the AC Transmission System.
[14] Refer to bullet #4 below.
[15] These conditions are referred to as the “may Ride-through zone”.
[16] Refer to bullet #4 below.
[17] These conditions are referred to as the “may Ride-through zone”.

1. Table 1 applies to type 3 and type 4 wind IBR or hybrid IBR that include wind, unless connected via a dedicated Voltage Source Converter - High Voltage Direct Current (VSC-HVDC) transmission facility.
2. Table 2 applies to all other IBR types not covered in Table 1; including, but not limited to, the following facilities:
   a. IBR, regardless of their energy resource, interconnecting via a dedicated VSC-HVDC transmission facility.
   b. Other IBR or hybrid IBR consisting of photovoltaic (PV) and BESS.
3. The applicable voltage for VSC-HVDC system with a dedicated connection to an IBR is on the AC side of the transformer(s) that is (are) used to connect the VSC-HVDC system to the interconnected transmission system.
4. The voltage base for per unit calculation is the nominal phase-to-ground or phase-to-phase transmission system voltage unless otherwise defined by the Planning Coordinator, Transmission Planner, or Transmission Owner.
5. The applicable voltage for Tables 1 and 2 is identified as the voltage max/min of phase-to-neutral or phase-to-phase fundamental root mean square (RMS) voltage at the high-side of the main power transformer.
6. Tables 1 and 2 are only applicable when the frequency is within the “must Ride-through zone” as specified in Figure 1 of Attachment 2.
7. At any given voltage value, each IBR shall Ride-through unless the time duration at that voltage has exceeded the specified minimum Ride-through time duration. If the voltage is continuously varying over time, it is necessary to add the duration within each band of Tables 1 and 2 over any 10 second time period.
8. The specified duration of the mandatory operation regions and the permissive operation regions in Tables 1 and 2 is cumulative over one or more disturbances within any 10 second time period.
9. The IBR may trip for more than four deviations of the applicable voltage at the high-side of the main power transformer outside of the continuous operation region within any 10 second time period.
10. Instantaneous trip settings based on instantaneously calculated voltage measurements with less than filtering lengths of one cycle (16.6 millisecond) are not permissible.
11. The “must Ride-through zone” is the combined area of the mandatory operating regions, the continuous operating regions, and the permissive operating region. All area outside of these operating regions is referred to as the “may Ride-through zone”.

Attachment 2: Frequency Ride-Through Criteria

Table 3: Frequency Ride-through Capability Requirements

System Frequency (Hz)	Minimum Ride-Through Time (sec)
> 61.8	May trip
> 61.2	299
≤ 61.2 and ≥ 58.8	Continuous
< 58.8	299
< 57.0	May trip

1. Frequency measurements are taken at the high-side of the main power transformer.
2. Frequency is measured over a period of time (typically 3-6 cycles) to calculate system frequency at the high-side of the main power transformer.
3. Instantaneous or single points of measurement may not be used in the determination of control settings.
4. At any given frequency value, each IBR shall Ride-through unless the time duration at that frequency has exceeded the specified minimum ride-through time duration.
5. The specified durations of Table 3 are cumulative over one or more disturbances within a 10-minute time period.

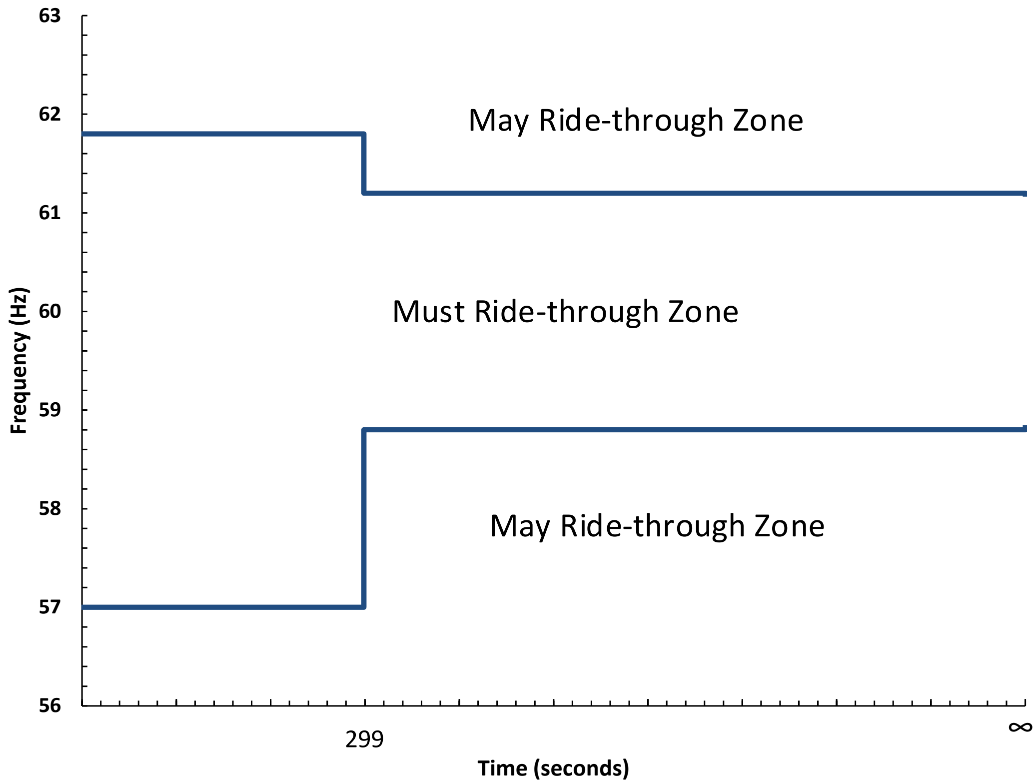

Figure 1: PRC-029 Frequency Ride-through Requirements

Implementation Plan

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
Reliability Standards PRC-024-4 and PRC-029-1

Applicable Standard(s)

- PRC-024-4 – Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and Type 2 Wind Resources, and Synchronous Condensers
- PRC-029-1 – Frequency and Voltage Ride-through Requirements for Inverter-based Generating Resources

Requested Retirement(s)

- PRC-024-3 Frequency and Voltage Protection Settings for Generating Resources

Prerequisite Standard(s)

- None

Applicable Entities

- See subject Reliability Standards.

New Terms in the NERC Glossary of Terms

This section includes all newly defined, revised, or retired terms used or eliminated in the NERC Reliability Standard. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Proposed New Definition(s):
Ride-through: The plant/facility remains connected and continues to operate through voltage or frequency system disturbances.

Background

The purpose of Project 2020-02 is to modify Reliability Standard PRC-024-3 or replace it with a performance-based Ride-through standard that ensures generators remain connected to the Bulk Power System (BPS) during system disturbances. Specifically, the project focuses on using disturbance monitoring data to substantiate inverter-based resource (IBR) ride-through performance during grid disturbances. The project also ensures associated generators that fail to Ride-through system events are addressed with a corrective action plan (if possible) and reported to necessary entities for situational awareness.

The purpose for this project is based on the culmination of multiple analyses conducted by the ERO Enterprise regarding widespread IBR tripping events. Furthermore, the NERC Inverter-Based Resource Performance Subcommittee[1] has developed comprehensive recommendations for improved performance of IBRs, including the recommendation to develop comprehensive ride-through requirements.

In October 2023, FERC issued Order No. 901[2] which directs the development of new or modified Reliability Standards that include new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. In January 2024, NERC submitted a filing to FERC outlining a comprehensive work plan to address the directives within Order No. 901.[3] Within the work plan, NERC identified three active Standards Development projects that would need to be filed for regulatory approval with FERC by November 4, 2024. These projects include **2020-02 Modifications to PRC-024 (Generator Ride-through)**[4], **2021-04 Modifications to PRC-002-2**[5], and **2023-02 Analysis and Mitigation of BES Inverter-based Resource Performance Issues**[6].

Project 2020-02
Proposed Reliability Standard PRC-029-1 is a new Reliability Standard that includes Ride-through requirements and performance requirements for IBRs. The scope of this project was adjusted to align with associated regulatory directives from FERC Order No. 901 and the scope of the other projects related to “Milestone 2” of the NERC work plan. The components of this project’s Standard Authorization Request (SAR) that related to the inclusions of new data recording requirements are covered in Project 2021-04 and the proposed new PRC-028-1 Reliability Standard. Components of this project’s SAR that relate to analytics and corrective actions plans are covered in Project 2023-02 and the proposed new PRC-030-1 Reliability Standard.

PRC-029-1 includes requirements for Generator Owner IBR to continue to inject current and perform voltage support during a BPS disturbance. The standard also specifically requires Generator Owner IBR to prohibit momentary cessation in the no-trip zone during disturbances.

PRC-024-4 includes modifications to revise applicable facility types to remove IBR, retain type 1 and type 2 wind, and to include synchronous condensers.

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[1] See documents at the NERC IRPS website: https://www.nerc.com/comm/RSTC/Pages/IRPS.aspx and the previous Inverter-Based Resource Performance Working Group website https://www.nerc.com/comm/RSTC/Pages/IRPWG.aspx
[2] See FERC Order 901, Docket No. RM22-12-000; https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false; October 19, 2023
[3] See INFORMATIONAL FILING OF THE NORTH AMERICAN RELIABILITY CORPORATION REGARDING THE DEVELOPMENT OF RELIABILITY STANDARDS RESPONSIVE TO ORDER NO. 901 https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/NERC%20Compliance%20Filing%20Order%20No%20901%20Work%20Plan_packaged%20-%20public%20label.pdf; January 17, 2024
[4] See NERC Standards Development Project page for Project 2002-02; https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx
[5] See NERC Standards Development Project page for Project 2021-04; https://www.nerc.com/pa/Stand/Pages/Project-2021-04-Modifications-to-PRC-002-2.aspx
[6] See NERC Standards Development Project page for Project 2023-02; https://www.nerc.com/pa/Stand/Pages/Project-2023-02-Performance-of-IBRs.aspx

General Considerations

This implementation plan recognizes the urgent need for Reliability Standards to address IBR ride through performance, as demonstrated by multiple event reports of the last decade, while providing a reasonable period of time for entities to develop the necessary procedures and change their protection and control settings to meet the new requirements. The ERO Enterprise acknowledges that there are IBRs currently in operation and unable to meet voltage Ride-through requirements due to their inability to modify their coordinated protection and control settings. Consistent with FERC Order No. 901, a limited and documented exemption process for those IBR is appropriate and included within this Implementation Plan. Other NERC Standards Development projects will be pursued to address ongoing identification and mitigation of any potential reliability impacts to the BPS for such exemptions.

This implementation plan also recognizes that certain requirements (Requirements R1, R2, and R3) call for entities to "ensure the design and operation" of their IBR units meets certain criteria. Design elements may be implemented more expeditiously than operation requirements; the latter of which will require entities to show compliance through use of actual disturbance monitoring data. Therefore, this implementation plan provides staggered timeframes by which entities shall first ensure the design of their IBR units meets the criteria (12 months following regulatory approval). Subsequent compliance with the "operation" elements of these requirements shall become due as entities install disturbance monitoring equipment on each applicable IBR in accordance with the implementation plan for proposed Reliability Standard PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-based Resources.

The ERO Enterprise acknowledges that Generator Owners and Generator Operators owning or operating Bulk Power System connected IBRs that do not meet NERC's current definition of Bulk Electric System ("BES") will be registered no later than May 2026 in accordance with the IBR Registration proceeding in FERC Docket No. RR24-2. To ensure an orderly registration and compliance process for these entities, as well as fairness and consistency in the standard's application among similar asset types, this implementation plan provides additional time for both new and existing registered entities to come into compliance with Reliability Standard PRC-029-1's requirements for their applicable IBRs not meeting the BES definition. In so doing, this implementation plan advances an orderly process for new registrants while allowing existing entities to focus their immediate efforts on their assets posing the highest risk to the reliable operation of the Bulk Power System.

Effective Date and Phased-in Compliance Dates

The effective dates for the proposed Reliability Standards are provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance dates for those particular sections represent the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

PRC-024-4

Where approval by an applicable governmental authority is required, Reliability Standard PRC-024-4 shall become effective on the first day of the first calendar quarter that is twelve months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the Reliability Standard PRC-024-4 shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

PRC-029-1 and definition of Ride-through

Where approval by an applicable governmental authority is required, Reliability Standard PRC-029-1 and the definition of Ride-through shall become effective on the first day of the first calendar quarter that is twelve months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the Reliability Standard PRC-029-1 and the definition of Ride-through shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

PRC-029-1 Phased-in Compliance Dates

Requirements R1, R2, and R3

Capability-Based Elements

Bulk Electric System IBRs

Entities shall comply with the portion of Requirements R1, R2, and R3 relating to the **design** of their BES IBRs to meet the requirements by the effective date of the standard.

Applicable Non-BES IBRs[7]

Entities shall not be required to comply with Requirements R1, R2, and R3 relating to the **design** of their applicable non-BES IBRs until the later of: (1) January 1, 2027; or (2) the effective date of the standard.

Performance-Based Elements (all applicable IBRs)

Entities shall not be required to comply with the portion of Requirements R1, R2, and R3 relating to the **operation** of IBRs to meet the requirements until the entity has established the required

[7] The standard defines such as IBRs as "Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV."

disturbance monitoring equipment capabilities for those IBRs in accordance with the implementation plan for Reliability Standard PRC-028-1.

Requirement R4

Bulk Electric System IBRs
Entities shall comply with Requirement R4 for their BES IBRs by the effective date of the standard.

Applicable Non-BES IBRs
Entities shall not be required to comply with Requirement R4 or their non-BES IBRs until the later of: (1) January 1, 2027; or (2) the effective date of the standard.

Retirement Date

PRC-024-3

Reliability Standard PRC-024-3 shall be retired immediately prior to the effective date of Reliability Standards PRC-024-4 and PRC-029-1 in the particular jurisdiction in which the revised standard is becoming effective.

Equipment Limitations and Process for Requirement R4

Consistent with FERC Order No. 901, a limited and documented exemption for some legacy IBR with certain documented equipment limitations are acceptable. Per the Order, these IBRs are

> "…typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements."[8]

To ensure compliance with Requirement R4 and alignment with FERC Order No. 901, only those IBR that are in operation as of the effective date of PRC-029-1 may be considered for potential exemption. Further, only those IBR that are unable to meet ride-through requirements due to their inability to modify their coordinated protection and control settings may be considered for potential exemption.

[8] Order No. 901 at p. 193.

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Implementation Plan

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
Reliability Standards PRC-024-4 and PRC-029-1

Applicable Standard(s)

- PRC-024-4 – Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and Type 2 Wind Resources, and Synchronous Condensers
- PRC-029-1 – Frequency and Voltage Ride-through Requirements for Inverter-based Generating Resources

Requested Retirement(s)

- PRC-024-3 Frequency and Voltage Protection Settings for Generating Resources

Prerequisite Standard(s)

- None

Applicable Entities

- See subject Reliability Standards.

New Terms in the NERC Glossary of Terms

This section includes all newly defined, revised, or retired terms used or eliminated in the NERC Reliability Standard. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Proposed New Definition(s):
Ride-through: The plant/facility remains connected and continues to operate through voltage or frequency system disturbances.

Background

The purpose of Project 2020-02 is to modify Reliability Standard PRC-024-3 or replace it with a performance-based Ride-through standard that ensures generators remain connected to the Bulk Power System (BPS) during system disturbances. Specifically, the project focuses on using disturbance monitoring data to substantiate inverter-based resource (IBR) ride-through performance during grid disturbances. The project also ensures associated generators that fail to Ride-through system events are addressed with a corrective action plan (if possible) and reported to necessary entities for situational awareness.

The purpose for this project is based on the culmination of multiple analyses conducted by the ERO Enterprise regarding widespread IBR tripping events. Furthermore, the NERC Inverter-Based Resource Performance Subcommittee[1] has developed comprehensive recommendations for improved performance of IBRs, including the recommendation to develop comprehensive ride-through requirements.

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PRC-029-1 includes requirements for Generator Owner IBR to continue to inject current and perform voltage support during a BPS disturbance. The standard also specifically requires Generator Owner IBR to prohibit momentary cessation in the no-trip zone during disturbances.

PRC-024-4 includes modifications to revise applicable facility types to remove IBR, retain type 1 and type 2 wind, and to include synchronous condensers.

[1] See documents at the NERC IRPS website: https://www.nerc.com/comm/RSTC/Pages/IRPS.aspx and the previous Inverter-Based Resource Performance Working Group website https://www.nerc.com/comm/RSTC/Pages/IRPWG.aspx

[2] See FERC Order 901, Docket No. RM22-12-000; https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false; October 19, 2023

[3] See INFORMATIONAL FILING OF THE NORTH AMERICAN RELIABILITY CORPORATION REGARDING THE DEVELOPMENT OF RELIABILITY STANDARDS RESPONSIVE TO ORDER NO. 901 https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/NERC%20Compliance%20Filing%20Order%20No%20901%20Work%20Plan_packaged%20-%20public%20label.pdf; January 17, 2024

[4] See NERC Standards Development Project page for Project 2002-02; https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx

[5] See NERC Standards Development Project page for Project 2021-04; https://www.nerc.com/pa/Stand/Pages/Project-2021-04-Modifications-to-PRC-002-2.aspx

[6] See NERC Standards Development Project page for Project 2023-02; https://www.nerc.com/pa/Stand/Pages/Project-2023-02-Performance-of-IBRs.aspx

General Considerations

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This implementation plan also recognizes that certain requirements (Requirements R1, R2, and R3) call for entities to "ensure the design and operation" of their IBR units meets certain criteria. Design elements may be implemented more expeditiously than operation requirements; the latter of which will require entities to show compliance through use of actual disturbance monitoring data. Therefore, this implementation plan provides staggered timeframes by which entities shall first ensure the design of their IBR units meets the criteria (12 months following regulatory approval). Subsequent compliance with the "operation" elements of these requirements shall become due as entities install disturbance monitoring equipment on each applicable IBR in accordance with the implementation plan for proposed Reliability Standard PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-based Resources.

The ERO Enterprise acknowledges that Generator Owners and Generator Operators owning or operating Bulk Power System connected IBRs that do not meet NERC's current definition of Bulk Electric System ("BES") will be registered no later than May 2026 in accordance with the IBR Registration proceeding in FERC Docket No. RR24-2. To ensure an orderly registration and compliance process for these entities, as well as fairness and consistency in the standard's application among similar asset types, this implementation plan provides additional time for both new and existing registered entities to come into compliance with Reliability Standard PRC-029-1's requirements for their applicable IBRs not meeting the BES definition. In so doing, this implementation plan advances an orderly process for new registrants while allowing existing entities to focus their immediate efforts on their assets posing the highest risk to the reliable operation of the Bulk Power System.

Effective Date and Phased-in Compliance Dates

The effective dates for the proposed Reliability Standards are provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance dates for those particular sections represent the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

PRC-024-4
Where approval by an applicable governmental authority is required, Reliability Standard PRC-024-4 shall become effective on the first day of the first calendar quarter that is twelve months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the Reliability Standard PRC-024-4 shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

PRC-029-1 and definition of Ride-through
Where approval by an applicable governmental authority is required, Reliability Standard PRC-029-1 and the definition of Ride-through shall become effective on the first day of the first calendar quarter that is twelve months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the Reliability Standard PRC-029-1 and the definition of Ride-through shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

PRC-029-1 Phased-in Compliance Dates

Requirements R1, R2, and R3

Capability-Based Elements

Bulk Electric System IBRs
Entities shall comply with the portion of Requirements R1, R2, and R3 relating to the **design** of their BES IBRs to meet the requirements by the effective date of the standard.

Applicable Non-BES IBRs[7]
Entities shall not be required to comply with Requirements R1, R2, and R3 relating to the **design** of their applicable non-BES IBRs until the later of: (1) January 1, 2027; or (2) the effective date of the standard.

Performance-Based Elements (all applicable IBRs)
Entities shall not be required to comply with the portion of Requirements R1, R2, and R3 relating to the **operation** of IBRs to meet the requirements until the entity has established the required

[7] The standard defines such as IBRs as "Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV."

disturbance monitoring equipment capabilities for those IBRs in accordance with the implementation plan for Reliability Standard PRC-028-1.

Requirement R4

Bulk Electric System IBRs
Entities shall comply with Requirement R4 for their BES IBRs by the effective date of the standard.

Applicable Non-BES IBRs
Entities shall not be required to comply with Requirement R4 or their non-BES IBRs until the later of: (1) January 1, 2027; or (2) the effective date of the standard.

Retirement Date

PRC-024-3

Reliability Standard PRC-024-3 shall be retired immediately prior to the effective date of Reliability Standards PRC-024-4 and PRC-029-1 in the particular jurisdiction in which the revised standard is becoming effective.

Equipment Limitations and Process for Requirement R4

Consistent with FERC Order No. 901, a limited and documented exemption for some legacy IBR with certain documented equipment limitations are acceptable. Per the Order, these IBRs are

> "…typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements."[8]

To ensure compliance with Requirement R4 and alignment with FERC Order No. 901, only those IBR that are in operation as of the effective date of PRC-029-1 may be considered for potential exemption. Further, only those IBR that are unable to meet ~~voltage~~ ride-through requirements due to their inability to modify their coordinated protection and control settings may be considered for potential exemption.

[8] Order No. 901 at p. 193.

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Standards Committee and NERC Ride-through Technical Conference

Conference Details

September 4-5, 2024 | 9:00 a.m. – 4:00 p.m. Eastern

Location: The Westin Washington, DC Downtown
999 9th St NW, Washington, DC 20001

Click here for: Virtual Registration Only
Click here for: Agenda
Click here for: Panel Questions

Background

On August 15, 2024, the NERC Board of Trustees (Board) invoked Section 321 of the NERC Rules of Procedure (ROP) to address critical and rapidly growing risk to the reliability of the Bulk Power System associated with inverter-based resources (IBR) in response to FERC Order No. 901 directives. PRC-029-1 (Frequency and Voltage Ride-through Requirements for Inverter-based Resources) is a draft standard designed to establish capability-based and performance-based Ride-through requirements for IBRs during grid disturbances. The draft standard failed to achieve consensus from the Registered Ballot Body over multiple ballots, calling into question whether development would be completed by FERC's filing deadline of November 4, 2024, which resulted in the Board acting under Section 321 of the ROP. Under this special authority, the Board directed the Standards Committee to work with NERC to host a technical conference. This technical conference will address the remaining issues for the proposed Ride-through standard (PRC-029-1). Using input from the technical conference, the proposed Reliability Standard will be revised as appropriate, then put to one more stakeholder ballot. If the standard achieves at least 60% stakeholder approval, the Board may consider it for adoption under this special process. There is a 45-day deadline to complete the process.

Meeting Format

This technical conference will be in-person near the NERC Washington, DC office – location to be announced - with a virtual option available. The technical conference will be recorded and transcribed. Recordings will be made available following the technical conference. Breakfast and lunch will be provided.

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Registration

In-person registration has reached capacity. Only virtual registrations are being accepted at this time.

Agenda

A detailed agenda will be provided. Some of the topics to be covered include:

1. the definition of Ride-through,
2. newly proposed criteria for frequency Ride-through performance, and
3. allowable hardware-based exemptions under FERC Order No. 901.

Submittal of Comments

As part of the preparation for the technical conference and to support the decisions by the Standards Committee and NERC, the public is encouraged to provide comments for consideration on the topics identified on the agenda. <u>In particular, any information on hardware-based limitations that would prevent IBR from meeting the proposed frequency criteria within PRC-029-1 is requested</u>. Commenters are advised this information will be used as part of the record of development and should not include information that would be considered Critical Energy/Electric Infrastructure Information (CEII) or proprietary information. Summarized, aggregated, or otherwise non identifying information that can be substantiated with verifiable data, is requested for these submittals. NERC may request follow-ups with individual commenters to review this data through separate and non-public mechanisms.

Include in Comments

1. Indicate if you are representing a NERC registered entity and, if so, which functional registrations.
2. Indicate if you are representing an original equipment manufacturer of IBR.
3. Indicate if your company provided comments through the Standards Development process for Project 2020-02 Modifications to PRC-024 (Generator Ride-through), to allow the team to cross reference previous information. If your entity is part of the Registered Ballot Body, also provide what segment(s) your company is in.
4. Provide comments specific to the proposed frequency Ride-through criteria.
5. Provide comments specific to the proposed Ride-through definition.
6. <u>Provide comments specific to hardware-based limitations that would prevent IBR from meeting the proposed frequency criteria within PRC-029-1.</u>

Instructions for Submittal

Please submit comments via email and include any attachments in PDF to the parties listed below:

- Jamie Calderon, Manager of Standard Development (jamie.calderon@nerc.net)
- Alison Oswald, Manager of Standard Development (alison.oswald@nerc.net)
- Lauren Perotti, Assistant General Counsel (lauren.perotti@nerc.net)
- Todd Bennett, Standards Committee Chair (tbennett@aeci.org)
- Troy Brumfield, Standards Committee Vice-Chair (lbrumfield@atcllc.com)

Comments received after August 27, 2024 will be accepted but may not be reviewed prior to completing the Board directed actions.

Agenda
Standards Committee and NERC Ride-through Technical Conference

September 4 - 5, 2024 | 9:00 a.m.- 4:00 p.m. Eastern

Location: The Westin Washington, DC Downtown
999 9th St NW, Washington, DC 20001

Wednesday, September 4, 2024

8:55 AM - 9:00 AM
Safety Briefing
Event Space Staff

9:00 AM - 9:05 AM
NERC Antitrust Compliance Guidelines and Commission Staff Disclaimer
NERC Staff

9:05 AM - 9:15 AM
Welcome and Opening Remarks – NERC Board of Trustees
Speaker: Rob Manning

9:15 AM - 9:25 AM
Opening Remarks – NERC
Speaker: Mark Lauby

9:25 AM - 9:35 AM
Opening Remarks – FERC
Speaker: David Ortiz

9:35 AM – 9:50 AM
Technical Conference Overview - Standards Committee
Speaker: Todd Bennett (AEC)
Introduction to the conference objectives. Walk through the agenda and expectations for next steps and interactions through any usage of Slido.

9:50 AM – 10:15 AM
Presentation: Summary Review of 901 and Milestone 2
Speaker: Jamie Calderon (NERC)
Summary overview of FERC Order 901, the associated Milestone 2 Reliability Standard projects and details of how those projects interrelate. Includes Q&A.

10:15 AM - 10:30 AM
Morning Break

10:30 AM - 11:15 AM
Presentation: Review of Voltage and Frequency Ride-through Criteria in PRC-029-1
Speakers: Husam Al-Hadidi and Shawn Wang (2020-02 Drafting Team Members)
Drafting Team members will review their approach to drafting PRC-029-1 along with key decisions made throughout the project development. Includes Q&A.

11:15 AM - 12:00 PM
Presentation: Review of Voltage and Frequency Ride-through Criteria
Speaker: Alex Shattuck (NERC)
A detailed review of proposed voltage and frequency criteria in used in the industry. This includes proposed criteria in PRC-024, PRC-029-1, and other criteria options such as IEEE 2800-2022. The presentation will explore the challenges associated with this requirement, particularly for existing generators, and will discuss known issues regarding quality of model data, issues obtaining capability information, and other issues that have been identified in recent NERC disturbance reports and NERC Alert reports. Includes Q&A.

12:00 PM - 1:00 PM
Lunch Break

1:00 PM - 2:00 PM
Panel Discussion: Original Equipment Manufacturer Perspectives on Voltage and Frequency Ride-through Criteria
Moderators: Alex Shattuck (NERC) and Charlie Cook (Duke Energy)
Panelists:

- Thomas Schmidt Grau (Vestas)
- Thierry Ngassa (Power Electronics)
- Scott Karpiel (SMA)
- Dinesh Pattabiraman (TMEIC)
- Samir Dahal (Siemens Energy)
- Arne Koerber (GE Vernova)

This session will focus on the challenges with meeting the proposed voltage and frequency criteria. This session is informed by original equipment manufacturer (OEM) concerns pertaining to the usage of different criteria values for both voltage and frequency, particularly in relation to older generators and FERC Order 901 directives. Panelists will discuss challenges and potential solutions aimed at maximizing Ride-through capability while balancing reliability needs and implementation practicality.

2:00 PM - 2:15 PM
Afternoon Break

2:15 PM – 3:00 PM
Panel Discussion with Q&A: Addressing the Challenges of Voltage and Frequency Ride-through Criteria
Moderators: Howard Gugel (NERC) and Charlie Cook (Duke Energy)
Panelists:

- Mark Lauby (NERC)
- Manish Patel (EPRI)
- Todd Chwialkowski (EDF)
- Andy Hoke (NREL)
- Michael Goggin (Grid Strategies LLC)

During this session, we will talk about the differences in the recommended voltage and frequency Ride-through Reliability Standards compared to other potential criteria. This discussion has been initiated due to concerns raised by stakeholders about using different standard values for voltage and frequency, especially with regards to older generators and FERC Order 901 directives. The panelists will examine possible solutions to find a middle ground between reliability needs and the feasibility of making adjustments to current protection and controller settings.

3:00 PM - 3:30 PM
Slido Polling: Voltage and Frequency Ride-through Criteria
Moderator: Amy Casuscelli (Xcel energy) and NERC Staff
Conference participants will be presented various options through Slido live polling to provide immediate feedback on proposed revisions to PRC-029-1 voltage and frequency Ride-through criteria. The session is intended to collect industry feedback to gauge consensus on definition revisions. The Standards Committee members assigned to revise PRC-029-1 will leverage these polling results as determined by the Standards Committee.

3:30 PM – 3:45 PM | **Parking Lot**

3:45 PM - 4:00 PM
Day 1 Wrap-Up
Board Member – Sue Kelly

Thursday, September 5th

9:00 AM - 9:15 AM
Recap of Day 1 and Introduction to Day 2
Todd Bennett (AEC) and Soo Jin Kim (NERC)

9:15 AM - 10:15 PM
Panel Discussion: Discussion on Frequency Ride-Through Exemptions in PRC-029-1
Moderators: Charles Yeung (SPP) and Alex Shattuck (NERC)
Panelists:

- Howard Gugel (NERC)
- Dane Rogers (OGE)
- Jason MacDowell (ESIG)
- Mark Ahlstrom (NextEra)

This session will focus on the differences posed by the proposed draft which does not include exemptions for hardware-based limitations in meeting frequency criteria. This session is informed by submitted stakeholder concerns pertaining to proposed PRC-029-1 providing no hardware-based limitations for frequency criteria. Panelists will discuss known limitations and what options are available to balance reliability needs with the practicality of implementation for older type IBR.

10:15 AM - 10:30 AM
Morning Break

10:30 AM - 11:00 AM
Presentation: Outlining Objectives of a Ride-through Definition
Speaker(s): Joel Anthes (2020-02 Drafting Team Member)
A thorough examination of the usage of the term “Ride-through” within NERC reports, IEEE, currently active Ride-through Reliability Standards, and other industry usage of this term. This presentation(s) will also review the proposed definition in the current draft of PRC-029-1 and a comparative analysis of other proposed definitions evaluated by the drafting team during development. Special attention will be given to stakeholder comments during the last draft ballot regarding the clarity and scope of terms such as "entire" and "in its entirety." The discussion will also emphasize the critical nature of finalizing a single definition for usage in NERC’s Glossary of Terms and associated Reliability Standards.

11:00 AM - 12:00 PM
Slido Polling: Gathering Stakeholder Input on Revised Definitions
Moderator: Amy Casuscelli (Xcel Energy)
Conference participants will be presented various options through Slido live polling to provide immediate feedback on proposed revisions to the Ride-through definition regarding this topic. The session is intended to collect industry feedback to gauge consensus on definition revisions. The Standards Committee members assigned to revise PRC-029-1 will leverage these polling results as determined by the Standards Committee.

12:00 PM - 1:00 PM
Lunch Break

1:00 PM – 1:15 PM
Presentation: Detailed Review of Milestone 2 Implementation Plans
Speaker: Jamie Calderon (NERC)
A comprehensive presentation, on the alignment of implementation plans and effective dates between PRC-028-1 and PRC-030-1, as related to PRC-029-1. The discussion will cover the importance of coordinating timelines to avoid gaps or overlaps that could compromise reliability or complicate compliance efforts.

1:15 PM - 2:00 PM
Panel Discussion: Strategizing Implementation Plans and Effective Dates
Moderator: Charles Yeung (SPP) and Jamie Calderon (NERC)
Panelists:

- Howard Gugel (NERC)
- Sam Hake (AES)
- Manish Patel (EPRI)
- Rhonda Jones (Invenergy)

This panel will discuss additional facts and circumstances to consider when developing strategies to effectively implement Milestone 2 Reliability Standards and aligning Implementation Plans and effective dates between PRC-028-1, PRC-029-1, and PRC-030-1. The discussion will explore the potential challenges and proposed solutions that assist industry in ensuring a smooth transition to these new standards, maintaining compliance, and minimizing the risk of any operational disruptions.

2:00 PM - 2:15 PM
Afternoon Break

2:15 PM - 2:45 PM
Slido Polling: Consensus on Implementation Plans
Moderator: Amy Casuscelli (Xcel Energy)
Conference participants will be presented various options through Slido live polling to provide immediate feedback on proposed revisions to PRC-029-1's Implementation Plan. The session is intended to collect industry feedback to gauge consensus on definition revisions. The Standards Committee members assigned to revise PRC-029-1 will leverage these polling results as determined by the Standards Committee.

2:45 PM - 3:15 PM:
Final Slido Polling: The Proposed Path Forward
Moderator: Amy Casuscelli (Xcel Energy)
A final set of polls will be conducted to gauge participant support for specific solutions discussed throughout the conference and any other recommendations identified. Th The Standards Committee members assigned to revise PRC-029-1 will leverage these polling results as determined by the Standards Committee.

3:15 PM – 3:45 PM
Parking Lot

3:45 PM - 4:00 PM:
Closing Remarks and Next Steps
Speakers: Sue Kelly (NERC) and Todd Bennett (AEC)

Standards Committee (SC) and NERC Ride-through Technical Conference Bio's

Standards Committee and NERC Leadership

Todd Bennett

Managing Director, Reliability Compliance & Audit Services Associated Electric Cooperative, Inc. and SC Chair

I have been active in the power industry for 23 years and directly involved with ERO initiatives since 2009. My industry background includes 7 years at Sho-Me Power Electric Cooperative which included roles as a transmission facility design engineer and director of power grid operations; and 15 years at AECI working in NERC compliance. My focus while at AECI has been operations, planning, and critical infrastructure protection issues. AECI is registered as a Jointly Registered Organization (JRO) for the following functions on behalf of a diverse set of organizations: BA, DP, GO, GOP, PC, RP, TO, TOP, TP, and TSP. Resolving issues based on these functional registrations has made me deeply aware of the current reliability issues and challenges that NERC and the industry are facing.

I have participated in multiple NERC & SERC industry groups and was a past chair of the SERC registered entity forum, the current chair of the NERC Standards Committee, and previous co-chair of the NERC Standing Committees Coordinating Group. My current role at AECI is the Managing Director of Reliability Compliance and Audit Services. My professional focus is management of the AECI NERC compliance program, participation in NERC standards development, participation in industry initiatives, monitoring compliance with effective standards, and implementation of an AECI Board approved internal audit work plan.

I obtained a BS in Engineering from the University of Missouri and an MS of Engineering Management from the Missouri Institute of Science & Technology. I am a registered Professional Engineer (PE) and have obtained Certified Internal Auditor (CIA) and Certification in Risk Management Assurance (CRMA) credentials as well.

Troy Brumfield

Regulatory Compliance Manager American Transmission Company and SC Vice Chair

Troy is an employee at American Transmission Company LLC (ATC) his current position is Manager Reliability Standards Compliance. In this role, Mr. Brumfield is responsible for leading the overall development, and directing the activities and execution of ATC's regulatory strategy (2) monitoring ATC's regulatory environment (3) representing ATC at industry committees and trade organization meetings; and (4) working with ATC legal staff to develop regulatory strategies and resolve compliance and enforcement related issues.

Mr. Brumfield is the Vice-Chair of the NERC Standards Committee (SC), Chair of the Standards Committee Process Subcommittee (SCPS) and serves as a member of the Standards Committee Executive Committee (SCEC).

Mr. Brumfield is also a member of the MRO Compliance Monitoring and Enforcement Program Advisory Council (CMEPAC). The CMEPAC provides advice and counsel to MRO's Board of Directors, staff, members and registered entities on topics like the development, retirement, and application of NERC Reliability Standards, risk assessment, compliance monitoring, and the enforcement of applicable standards.

He has served as a chair and contributing member of several NERC Standards Drafting Teams and NERC Initiative Teams. These include NERC Project 2017-07 Standards Alignment with Registration, Guidelines and Technical Basis (GTB) Review Team, Standards Efficiency Review-Phase 1 Team (sub-team chair), Member of NERC Compliance and Certification Committee-ERO Monitoring Subcommittee, Observer and Active participant in the 2018-03 Standards Efficiency Review Retirements project, and Member of MRO NERC Standards Review Forum.

Prior to joining ATC Mr. Brumfield was employed at Wisconsin Energy Corporation (WEC). While at WEC Mr. Brumfield held various leadership roles in the Operations and Engineering-Major Projects work group and the Operations Support group where he was responsible for managing regulatory obligations, standards development, compliance, and asset management. During his time at WEC Mr. Brumfield served as Chair of several generation and distribution regional committees and councils that were tasked with promoting and strengthening governmental and industry partnerships. Mr. Brumfield utilized these committees and councils as a forum to facilitate discussions related to standards interpretation and standards execution by utility and governmental employees focused on the reliable design, construction, operation, and maintenance of electric and gas facilities.

Mr. Brumfield earned a Bachelor of Applied Science in Electronics Engineering Technology. He also earned a Master of Science in Engineering Management from the Milwaukee School of Engineering University

Robin Manning

Board of Trustees Member, NERC

Robin E. Manning was elected to the NERC Board of Trustees in February 2018. Mr. Manning is the chair of the Compliance Committee and serves on the Enterprise-wide Risk and Technology and Security Committees and as the Reliability and Security Technical Committee observer. Prior to joining the Board, Mr. Manning served as vice president of Transmission and Distribution Infrastructure for the Power Delivery and Utilization research sector at the Electric Power Research Institute (EPRI). He had overall management and technical responsibility for the annual research activities conducted by EPRI's transmission and distribution programs in collaboration with its global membership. Prior to joining EPRI, Mr. Manning served as an executive vice president with the Tennessee Valley Authority (TVA) from 2008 to 2014, where he was responsible at different times during his tenure for external relations, shared services, and power systems operations, and served as Chief Energy Delivery Officer. Previously, he served as vice president at Duke Energy, with responsibility for power delivery and gas transmission. Mr. Manning served on the University of Houston Engineering Leadership Board and serves as immediate past president of the North Carolina State Engineering Foundation Board. He is also the president of One Heart Global Ministries, a non-profit ministry organization. Mr. Manning received a bachelor's degree in Electrical Engineering from North Carolina State University where he was recently named to the NC State Electrical and Computer Engineering Hall of Fame. He also holds a master's degree in Business Administration from Queens College in Charlotte, North Carolina.

Sue Kelly

Board of Trustees Member, NERC

Susan (Sue) Kelly was elected to the NERC Board of Trustees in February 2021 and serves on the Finance and Audit, Nominating, Regulatory Oversight, and Technology and Security Committees. Ms. Kelly also serves as the observer for the Reliability and Security Technical Committee and Standards Committee. Ms. Kelly previously served as president and CEO of the American Public Power Association (APPA) from 2014 to 2019, where she led the national trade association serving public power utilities. She came to APPA in 2004 as its senior vice president of Policy Analysis and General Counsel and was responsible for APPA's energy policy formulation and policy advocacy before FERC, the federal courts, and other governmental and industry policy forums. Ms. Kelly has served on a number of committees, including the Steering Committee of the Electricity Subsector Coordinating Council (2014 to 2019), the Commodity Futures Trading Commission's Energy and Environmental Markets Advisory Committee (2015 to 2019), the U.S. Department of Energy's Electricity Advisory Committee (2008 to 2009 under the Bush Administration; 2012 to 2014 under the Obama Administration), and as the president of the Energy Bar Association (2010 to 2011). She was also a member of the Board of Directors of the Center for Energy Workforce Development. She currently serves on the Energy Bar Association's Masters Council and helped start a virtual mentoring program for Energy Bar Association members. She also serves on the E Source Advisory Board. Ms. Kelly was named one of Washington's "Most Powerful Women" in the November 2015 issue of Washingtonian magazine in the "Business, Labor, and Lobbying" category. In March 2017, she was honored as Woman of the Year by the Women's Council on Energy and the Environment. In January 2020, she received Public Utility Fortnightly's Owen Young Award to honor her exceptional contributions to the electric utility industry. Ms. Kelly earned her bachelor's degree in Honors Interdisciplinary Studies and Economics from the University of Missouri and her juris doctorate from George Washington University, both with high honors.

Mark Lauby

Senior Vice President and Chief Engineer, NERC

Mark G. Lauby is senior vice president and chief engineer at NERC. Mr. Lauby joined NERC in January 2007 and has held several positions, including vice president and director of Standards and vice president and director of Reliability Assessments and Performance Analysis. In 2012, Mr. Lauby was elected to the North American Energy Standards Board and was appointed to the Department of Energy's Electric Advisory Committee by the Secretary of Energy in 2014. Mr. Lauby has served as chair and is a life member of the International Electricity Research Exchange and served as chair of several Institute of Electrical and Electronics Engineers (IEEE) working groups. From 1999 to 2007, Mr. Lauby was an appointed member of the Board of Excellent Energy International Co., Ltd., an energy service company based in Thailand. He has been recognized for his technical achievements in many technical associations, including the 1992 IEEE Walter Fee Young Engineer of the Year Award. He was named a Fellow by IEEE in November 2011 for "leadership in the development and application of techniques for bulk power system reliability." In 2014, Mr. Lauby was awarded the IEEE Power and Energy Society's Roy Billinton Power System Reliability Award. In 2020, the National Academy of Engineering elected Mr. Lauby as a member, citing his development and application of techniques for electric grid reliability analysis. He is also a member of the IEEE Power & Energy Society (PES) Executive Advisory Committee, focused on providing strategic support to the PES Board of Directors. Prior to joining NERC, Mr. Lauby worked for the Electric Power Research Institute (EPRI) for 20 years, holding several senior positions, including: director, Power Delivery and Markets; managing director, Asia, EPRI International; and manager, Power System Engineering in the Power System Planning and Operations Program. Mr. Lauby began his electric industry career in 1979 at the Mid-Continent Area Power Pool in Minneapolis, Minnesota. His responsibilities included transmission planning, power system reliability assessment, and probabilistic evaluation. Mr. Lauby is the author of more than 100 technical papers on the subjects of power system reliability, expert systems, transmission system planning, and power system numerical analysis techniques. He earned his bachelor's and master's degrees in electrical engineering from the University of Minnesota. In addition, Mr. Lauby attended the London Business School Accelerated Development Program as well as the Executive Leadership Program at Harvard Business School.

Soo Jin Kim
Vice President of Engineering and Standards, NERC

Soo Jin Kim is the vice president of Engineering and Standards. In this role, she is responsible for providing engineering analysis and support for NERC activities and directing all aspects of NERC's continent-wide standards development process by providing oversight, guidance, coordination, and industry education around the development of Reliability Standards. Throughout her time at NERC, Ms. Kim has worked on numerous initiatives involving Standards, Compliance, and coordination across the ERO Enterprise. She joined NERC in 2012 as a standards developer and has since served as reliability manager and senior manager of Standards. From 2020 to 2023, she served as director of Power Risk Issues and Strategic Management (PRISM) where she transformed the group into a cross-cutting department that serves as technical advisors to other NERC functions. Under her leadership, PRISM initiated several projects to tackle energy assurance risks, particularly those addressing extreme weather challenges. Most notably, her team was instrumental in the formation of the Energy Reliability Assessment Task Force and the efforts to provide the technical support for registering new inverter-based resources. She also works with the Reliability Issues Steering Committee, and she was an integral leader in planning and executing the 2023 NERC Leadership Summit. Prior to joining NERC, Ms. Kim was an associate at Troutman Sanders LLP in Washington, D.C. in their Energy Practice. At Troutman Sanders, she worked on a variety of Federal Energy Regulatory Commission compliance matters. Prior to attending law school, she was a consultant/business analyst with various consulting firms focused on energy and commodity trading. Ms. Kim has a bachelor's degree in Economics and English from the University of Georgia and her juris doctor degree from American University, Washington College of Law. She is licensed to practice law in Georgia and Washington, D.C. She also served for five years on the board of the Women's Energy Network and as co-president for two of those years.

David Ortiz

Director of the Office of Electric Reliability, FERC

David is the Director of the Office of Electric Reliability (OER) at the Federal Energy Regulatory Commission. OER helps the Commission to oversee the reliability and security of the electric grid. OER's responsibilities include oversight of the North American Electric Reliability Corporation in its development and enforcement of mandatory reliability and cybersecurity standards. David leads over 90 staff, including electrical engineers, statisticians, attorneys and analysts. OER's recent accomplishments include: a standard ensuring that the grid can operate through extreme cold weather; standards for securing the supply chain for grid-related cyber systems and protecting the integrity and availability of grid communications; a standard requiring increased grid cybersecurity incident reporting; a rule requiring new generators to be able to provide frequency response, ensuring reliability of the grid as it incorporates more renewable resources; a standard protecting the grid from solar storms; a series of reports documenting utility best practices in grid restoration and recovery; and a series of best practice reports in utility cybersecurity.

From 2013 to 2016, David was a Deputy Assistant Secretary for Energy Infrastructure Modeling and Analysis (EIMA) in the Office of Electricity Delivery and Energy Reliability at the Department of Energy. From 1998 through 2013, David worked at the RAND Corporation, where he built a program of energy policy research and analysis.

David earned his doctorate in Electrical Engineering from the University of Michigan. He graduated from Princeton University.

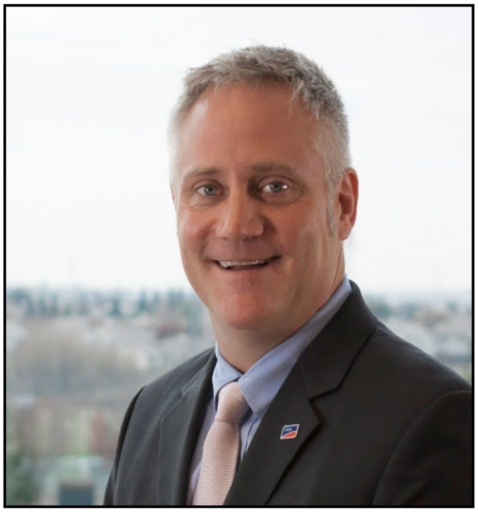
David lives in Falls Church, Virginia with his wife, Nicole, and two children. He is an avid tennis player, cyclist, home cook, and musician.

Panelists – Original Equipment Manufacturer Perspectives on Voltage and Frequency Ride-through Criteria

Thomas Schmidt Grau

Global Lead for RMS and EMT Development and Strategies for Vestas

Thomas has 15 years of experience in the industry in power plant systems. Started my career in Vestas working on system impact studies. Moved into modeling and became the global lead for all RMS and EMT development and strategies, supporting all markets Vestas is represented in. Nearly 5 years in the US being the Director for our Power Plant Solutions group, having grid accountability across Development, Sales, Construction, and Service. My focus is on supporting renewable growth and ensuring Vestas takes accountability in the renewable transition, especially around models and ensuring the right quality is provided for utilities to carry out reliable studies and ensure grid reliability for a green energy transition.



Scott Karpiel

Principal Application Engineer, SMA America

Scott Karpiel is a Principal Application Engineer at SMA America, the U.S.-based subsidiary of solar and storage inverter leader SMA Solar Technology AG, headquartered in Germany.

In this role, he provides design and consultation services, as well as technical support, for North American photovoltaic (PV) and storage customers, engineers, developers, owners and utilities. He also is responsible for identifying market requirements with his involvement in inverter-based resources working groups and standards drafting teams to drive product enhancements and bridge any technical gaps in the product offering. He is a subject-matter expert on utility scale renewable energy generation.

Karpiel, who joined SMA as an application engineer, has more than 30 years of experience in various engineering disciplines, including architectural engineering, quality engineering, compliance engineering, research and development, hardware engineering and technical support. Previous rolls in the renewable sector include commissioning, field engineering, product management and Director of Applications Engineering for various inverter manufacturers.

Karpiel earned a Bachelor of Science degree in electrical engineering, with a focus on energy conversion and power electronics from the University of Colorado, Boulder.

Dinesh Pattabiraman

Development Engineer in the Product Development Group at TMEIC Corporation Americas

Dinesh is currently working as a Development Engineer in the Product Development group at TMEIC Corporation Americas. He is experienced in power electronics hardware, control, modeling and power system dynamic performance studies. In his current role, he supports EMT modeling of TMEIC inverters, helping clients through interconnection studies and compliance with interconnection requirements and resolving inverter performance issues during grid events. Dinesh completed his PhD and M.S. in Electrical Engineering from the University of Wisconsin-Madison and his bachelor's in electrical & Electronics Engineering from the National Institute of Technology – Trichy, India.

Samir Dahal

Manager of Grid Interconnection and Modeling for Siemens Gamesa Renewable Energy

Samir Dahal is a seasoned electrical engineer who manages grid interconnection and modeling efforts at Siemens Gamesa Renewable Energy, overseeing over 10 GW of onshore projects across the Americas. He has extensive experience leading generator interconnection studies, managing engineering teams, and developing inverter models, previously serving as a Principal Consulting Engineer at Mitsubishi Electric Power Products Inc.

Samir holds a Ph.D. in Electrical Engineering from the University of North Dakota and a Bachelor's degree from NYU Tandon School of Engineering. His expertise spans renewable energy, power systems, and grid integration, supported by a strong research background and multiple academic honors.

Arne Koerber

Product Line Leader for GE Vernova

Dr. Arne Koerber is the Product Line Leader, Controls & Software for GE Vernova's wind business. In this role, he leads product strategy for control and software systems including turbine and plant-level controls, SCADA, farm optimization, grid integration, and condition monitoring systems.

Arne joined GE in 2008 and has held a number of roles focused on system simulation and controls engineering both in Europe and the US including leading Controls & Operability Engineering for GE's Onshore Wind business.

Arne graduated from TU Berlin, Germany with a degree in Engineering Science and holds a PhD in Control Systems from the same University.

Moderator(s)

Alex Shattuck

Senior Engineer, Engineering & Security Integration, NERC

Alex Shattuck is a Senior Engineer in the Engineering and Security Integration department at the North American Electric Reliability Corporation. He contributes heavily on a number of NERC's efforts related to grid transformation including initiatives focused on inverter-based resources, distributed energy resources, integrating security with conventional engineering practices, and emerging technologies. In addition to helping to lead NERC's IBR activities, Alex currently coordinates NERC's Inverter-based Resource Performance Subcommittee and has experience throughout the industry through work as a modeling subject matter expert at an IBR equipment manufacturer, modeling lead at a power engineering consultancy, and as a planning engineer at an Independent System Operator.

Charlie Cook

Lead Compliance Analyst for Duke Energy and SC Member

Charlie Cook is a seasoned Regulator Compliance Specialist with over 25 years of experience in the industry. With a strong background in Internal Controls and Audits, he has participated in numerous assessments of several companies' adherence to regulatory requirements. As a driven and detail-oriented professional, Charlie is dedicated to ensuring that every project achieves the highest level of quality and meets the needs of clients. When not working, Charlie enjoys boating and off-roading and participates in volunteer and charitable fund-raising events as a member of his local Masonic Lodge.

Panelists – Panel Discussion with Q&A: Addressing the Challenges of Voltage and Frequency

Mark Lauby – Senior Vice President and Chief Engineer, NERC Bio located with the Executive Team

Manish Patel

Technical Executive for Electric Power Research Institute (EPRI)

Manish Patel, PhD, PE is a Technical Executive at Electric Power Research Institute (EPRI) since April 2024. Before EPRI, he was with Southern Company for 17.5 years in various roles, with experience in Protection & Control and Transmission Planning. He is an active member of the IEEE Power System Relaying Committee. He is a registered Professional Engineer in the state of Alabama.

Todd Chwialkowski

Director, Transmission Regulatory and Compliance for EDF Renewables

Todd Chwialkowski is a Director of Regulatory and Compliance for EDF Renewables. He is currently based out of Denver, CO. Prior to this position at EDFR, Todd worked as a Manager of NERC Business Development and NERC Compliance Subject Matter Expert, and Senior Project Manager, Cyber Security, contracting at the Department of Interior, Bureau of Reclamation in their Power Resources Office. He earned an engineering degree from the University of Minnesota, and his MBA from the American Military University. He is a current Certified Information Systems Security Professional (CISSP) and a Certified Information Systems Auditor (CISA).

Andy Hoke

Principal Engineer in the Power Systems Engineering Center at the National Renewable Energy Laboratory (NREL)

Andy Hoke is a principal engineer in the Power Systems Engineering Center at the National Renewable Energy Laboratory (NREL), where he has worked for the past 14 years. He received the Ph.D. and M.S. degrees in Electrical, Computer, and Energy Engineering from the University of Colorado, Boulder, in 2016 and 2013, respectively. Dr. Hoke’s expertise is in grid integration of power electronics and inverter-based renewable and distributed energy. His work includes power systems modeling and simulation, advanced inverter controls design, hardware-in-the-loop testing and model development, and standards development. He has served as Chair of IEEE 1547.1-2020 and P2800.2, which contain the test and verification procedures to ensure DERs and inverter-based resources conform to the grid interconnection requirements of IEEE Standards 1547 and 2800, respectively. He is a registered professional engineer in the State of Colorado.

Michael Goggin

Consultant for Grid Strategies LLC

Michael Goggin has worked on renewable energy, transmission, and reliability issues for 20 years. He has testified in dozens of state regulatory and FERC proceedings on those topics. At Grid Strategies he serves as a consultant for a range of clean energy industry clients. For the preceding 10 years he held various positions at the American Wind Energy Association, now known as the American Clean Power Association. Michael has previously served on the NERC Standards, Operating, and Planning Committees. He graduated with honors from Harvard University.

Moderator(s)

Howard Gugel

Vice President of Regulatory Oversight, NERC

Howard Gugel is the vice president of Regulatory Oversight at NERC. In this role, he is responsible for directing programs and processes to monitor, review, and evaluate program effectiveness of the Electric Reliability Organization (ERO) Enterprise's implementation of risk-based compliance monitoring and enforcement. This includes adherence to the NERC Rules of Procedure, the Compliance Monitoring and Enforcement Program, and approved delegation agreements. He is also responsible for overseeing the ERO's Organization Registration and Certification process. Prior to this, he was vice president of Engineering and Standards at NERC. In this role, he provided engineering analysis and support for NERC activities and directed all aspects of NERC's continent-wide standards development process by providing oversight, guidance, coordination, and industry education of the development of Reliability Standards. He also previously served as the director of Performance Analysis, where he was responsible for the development, maintenance, and analysis of reliability performance metrics, including those in NERC's annual State of Reliability report. This included analyzing various databases of transmission and generations outages to look for statistically significant trends. In 2022, Mr. Gugel was appointed to the Department of Energy's Electric Advisory Committee by the Secretary of Energy. He also serves on the North American Energy Standards Board. Mr. Gugel has more than 34 years of experience in the electric utility industry. Prior to joining NERC, he was a transmission area maintenance manager for Progress Energy Florida, where he managed a staff of field personnel who maintained transmission lines and substation equipment. Prior to that, he was a transmission planning manager, also for Progress Energy Florida. His background includes management experience in operations and energy marketing. He has worked for two investor-owned utilities, a rural electric cooperative, and an energy marketing firm. Mr. Gugel earned his bachelor's and master's degree in Electrical Engineering from the University of Missouri – Rolla. He is a licensed professional engineer in Missouri.

Panelists – Discussion on Frequency Ride-through Exemptions in PRC-029-1

Howard Gugel – Vice President of Regulatory Oversight, NERC Bio located above

Dane Rogers

Lead NERC Compliance Analyst for Oklahoma Gas and Electric Company (OG&E)

Dane Rogers is a Lead NERC Compliance Analyst for Oklahoma Gas and Electric Company (OG&E). He is responsible for ensuring compliance with current O&P NERC Reliability Standard as well as monitoring new and revised Standards, assessing feasibility and impact, and coordinating Company position for balloting and commenting. He is actively engaged in multiple industry trade groups, serving as the Chair of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF), and serving on the Advisory Committee of the North American Generator Forum (NAGF).

In addition to his compliance experience at OG&E, Dane has held process and plant engineering positions at a synchronous generating facility as well as an operational reliability engineering position on the distribution system. Dane has also worked as a Quality Manager at a high-speed manufacturing facility owned by AB-InBev.

Prior to earning his BS in Mechanical Engineering from Oklahoma State University, Dane served in the Oklahoma Army National Guard.

Mark Ahlstrom

Vice-President, Renewable Energy Policy for NextEra Energy Resource

Mark Ahlstrom is Vice President of Renewable Energy Policy for NextEra Energy Resources and President of the Board of Directors of the Energy Systems Integration Group. He currently serves on NERC's Reliability Issues Steering Committee and chairs the SPP Future Grid Strategy Advisory Group, and he previously served on the NERC Essential Reliability Services Working Group and the NERC Integrating Variable Generation Task Force. Today, Mark focuses on rapid grid transformation pathways that are accelerated by the Inflation Reduction Act of 2022 with emphasis on reliability, economics, and innovation. Mark is a senior member of IEEE and a CIGRE member.

A biochemistry and biomedical engineering graduate of the University of Wisconsin-Madison, Mark initially worked as a software engineer at Honeywell Avionics and then as an artificial intelligence researcher at the Honeywell Computer Sciences Center before leaving to be founder of two software companies. In late 2000 he became CEO of WindLogics, a venture-funded computational weather modeling company that applied its technologies to improved understanding of wind energy projects. WindLogics was acquired in 2006 and is now the NextEra Analytics division of NextEra Energy Resources—America's premier clean energy leader and the world's largest producer of wind and solar energy.

Moderator(s)

Charles Yeung

Executive Director Interregional Affairs Southwest Power Pool

Charles H. Yeung is Executive Director of Interregional Affairs for the Southwest Power Pool (SPP). Since 2004, he has been responsible for leading SPP in the development of reliability and business standards at the national and continent-wide level. He is also SPP's primary contact to the ISO RTO Council's Standards Review Committee (SRC), a multi-member ISO/RTO group who works closely with ISO/RTO CEOs to formulate regulatory policy and to assess proposals for reliability standards and business practices impacting ISO/RTO reliability and markets.

Mr. Yeung has experience in the engineering and the regulatory side of electric utilities. His first professional employment was in 1988 at Houston Lighting & Power Co, (HL&P, now Centerpoint Energy). There Mr. Yeung worked as a relay protection engineer and engineered transmission protection systems to ensure safe and reliable operations of transmission networks in the HL&P service territory. He also calculated power flow information for transmission service contracts in the 1990's prior to FERC Order 888 for Open Access. In 1995 he began work in the HL&P Regulatory Department where he was involved in creating rules for the formation of ERCOT, the Texas regional transmission organization.

Mr. Yeung is a 1988 graduate of Texas A&M College Station with a bachelor's degree in electrical engineering and is a registered Professional Engineer. He also holds a Master of Business Administration from the University of Houston

Alex Shattuck – Senior Engineer, Engineering & Security Integration, NERC Bio located above

Panelist(s) – Strategizing Implementation Plans and Effective Dates

Howard Gugel – Vice President of Regulatory Oversight, NERC Bio located above

Sam Hake

NERC Compliance Engineer for AES Clean Energy

I have been part of the energy sector since 2015. In 9 years, I have had several different roles including NERC Compliance support, Transmission Planning, Asset Management, and P&C Engineering. Currently, I am supporting the NERC Compliance Program at AES Clean Energy as a NERC Compliance engineer. In this role I have experience working with Operations and Planning experts, focusing on the PRC suite of Standards, supporting integration and operation of renewable resources. Prior to joining AES Clean Energy I spent six years at Eversource Energy. At Eversource I had the opportunity to be part of several different departments including NERC Compliance, Asset Management, and Protection and Controls Engineering. Before joining Eversource, I was with Burns & McDonnell for two years working as a Transmission Planning Engineer.

Manish Patel – Technical Executive for Electric Power Research Institute (EPRI) Bio located above

Rhonda Jones

Vice President of Reliability Compliance at Invenergy LLC

As a 14-year NERC Regulatory Compliance leader, she administers Invenergy's NERC Compliance Programs. Her teams are responsible for ensuring 70+ power generation companies, across North America and Canada, are positioned to demonstrate how its strong operational practices adhere with regulations. The effectiveness of the programs is based on the promotion of reliable and safe operations, continuous training and development, interwoven internal controls, standards development participation, and a depth of both regulatory and technical expertise. Additionally, Rhonda leads Invenergy's RTO/ISO Market Registration & Compliance Program.

Rhonda served as a founder and chair of Black and Brown at Invenergy, an employee affinity group focused on increasing awareness, presence, opportunity, and participation, for people of African ancestry in sustainable energy careers. Rhonda is also a member of Invenergy's DEI Corporate Committee and a contributor to North American Generator Forum efforts.

She holds a BBA in Accounting, an MBA and a Juris Doctorate.

When this change agent takes a break from promoting grid resiliency, she enjoys hosting events, teaching Business Ethics and DEI in the Workplace, and live music.

Moderator(s)

Charles Yeung – Executive Director Interregional Affairs Southwest Power Pool Bio located above

Jamie Calderon

Manager, Standards Development, NERC

Jamie joined NERC in 2015 as an engineer developing Reliability Assessments and transitioned in 2017 to a senior engineer role with Compliance Assurance. Prior to joining NERC, Jamie served as a Transmission Planning Engineer and Bulk Power dispatcher for the Municipal Electric Authority of Georgia (MEAG). Jamie Calderon received her bachelor's degree of science in Electrical Engineering Technology from Southern Polytechnic State University in Marietta, Georgia.

Standards Committee & NERC Ride-Through Technical Conference

Panel Questions

September 4 – 5, 2024 | 9:00 a.m.- 4:00 p.m. Eastern

Location: The Westin Washington, DC Downtown
999 9th St NW, Washington, DC 20001

Wednesday, September 4, 2024

Panel Discussion: Original Equipment Manufacturer Perspectives on Voltage and Frequency Ride-through Criteria

This session will focus on the challenges with meeting the proposed voltage and frequency criteria. This session is informed by original equipment manufacturer (OEM) concerns pertaining to the usage of different criteria values for both voltage and frequency, particularly in relation to older generators and FERC Order 901 directives. Panelists will discuss challenges and potential solutions aimed at maximizing Ride-through capability while balancing reliability needs and implementation practicality.

Questions:

1. Do you anticipate challenges with your equipment meeting the voltage Ride-through criteria as specified in Attachment 1 of the draft PRC-029?
   a. If so, do you have an estimate for how many products would be affected?
   b. How does this estimate change when considering IEEE 2800-2022 criteria?
   c. How does this estimate change when considering PRC-024 boundaries?
2. Do you anticipate challenges with your equipment meeting the frequency Ride-through criteria as specified in Attachment 2 of the draft PRC-029?
   a. If so, do you have an estimate for how many products would be affected?
   b. How does this estimate change when considering IEEE 2800-2022 criteria?
   c. How does this estimate change when considering PRC-024 boundaries?
3. What documentation is necessary from manufacturers to prove which hardware limitations exist that would prevent your equipment from meeting the criteria in draft PRC-029 Attachments 1 and Attachment 2?
4. What documentation are you comfortable sharing with Generator Owners (GO), Transmission Planners, or NERC?

5. What is the generalized length of time associated with any redesign of current products to meet the criteria specified in PRC-029 without exception?
6. Are there any future or currently in design products able to meet the criteria in PRC-029?

Panel Discussion with Q&A: Addressing the Challenges of Voltage and Frequency Ride-through Criteria

During this session, we will talk about the differences in the recommended voltage and frequency Ride-through Reliability Standards compared to other potential criteria. This discussion has been initiated due to concerns raised by stakeholders about using different standard values for voltage and frequency, especially with regards to older generators and FERC Order 901 directives. The panelists will examine possible solutions to find a middle ground between reliability needs and the feasibility of making adjustments to current protection and controller settings.

Questions:

1. Approximately what percentage of GO portfolios are potentially affected by PRC-029 draft criteria. How does this change if thresholds are lowered to 2800-2022 criteria?
2. What are reasonable solutions to ensure legacy equipment can be compliant with voltage criteria in draft PRC-029 Attachment 1.
3. What are reasonable solutions to ensure legacy equipment can be compliant with frequency criteria in draft PRC-029 Attachment 2.
4. Do you expect equipment to fail to meet the voltage Ride-through criteria as specified in Attachment 1 of the draft PRC-029 due to hardware limitations?
   a. If so, do you have an estimate for how many products would be affected?
   b. How does this estimate change when considering IEEE 2800-2022 criteria.
   c. How does this estimate change when considering PRC-024 boundaries?
5. What considerations are needed regarding software-based maximizations to optimize voltage and frequency Ride-through capabilities?

Thursday, September 5, 2024

Panel Discussion: Discussion on Frequency Ride-through Exemptions in PRC-029-1

This session will focus on the differences posed by the proposed draft which does not include exemptions for hardware-based limitations in meeting frequency criteria. This session is informed by submitted stakeholder concerns pertaining to proposed PRC-029-1 providing no hardware-based limitations for frequency criteria. Panelists will discuss known limitations and what options are available to balance reliability needs with the practicality of implementation for older type Investor-based Resources (IBR).

Questions:

1. What are the financial and practical impacts between hardware-based and software-based solutions?
2. What is the timeline of software-based updates necessary to meet PRC-029 draft criteria? How does this timeline differ from hardware-based updates?
3. Do you expect equipment to fail to meet the frequency Ride-Through criteria as specified in Attachment 2 of the draft PRC-029 due to hardware limitations.
    a. If so, do you have an estimate for how many products would be affected?
    b. How does this estimate change when considering IEEE 2800-2022 criteria?
    c. How does this estimate change when considering PRC-024 boundaries?
4. What difficulties do GOs have when attempting to obtain hardware limitation data from OEM?
5. What difficulties do GOs have when attempting to coordinate their plant to successfully meet the criteria specified in Attachment 2 of the draft PRC-029?
6. Many commenters have said that it would only be fair to grandfather existing facilities and in-construction facilities from ride through requirements due to the costs of retrofitting. Other commenters have said that their facilities have an expected shelf life of up to 30 years, meaning there may be facilities in place in 2050 - when IBR penetration is expected to be much higher - that are not able to comply with requirements NERC wrote in 2024. How should NERC balance the burden on generators who may be asked to incur large retrofitting costs, with the burden on Transmission Owners, Transmission Planners, and end-use customers from poor or unexpected IBR performance?

Panel Discussion: Strategizing Implementation Plans and Effective Dates

This panel will discuss additional facts and circumstances to consider when developing strategies to effectively implement Milestone 2 Reliability Standards and aligning implementation plans and effective dates between PRC-028-1, PRC-029-1, and PRC-030-1. The discussion will explore the potential challenges and proposed solutions that assist industry in ensuring a smooth transition to these new Reliability Standards, maintaining compliance, and minimizing the risk of any operational disruptions.

Questions:

1. Given the complexities of aligning PRC-028-1, PRC-029-1, and PRC-030-1, what strategies would you recommend in synchronizing implementation to avoid conflicts or gaps in compliance? What considerations are needed to prevent potential overlaps or inconsistencies between implementation plans?
2. What do you anticipate will be the most significant challenges when retrofitting or modifying legacy IBR to comply with these new standards? Can you share any practical solutions or best practices that have proven effective in ensuring compatibility and minimizing operational disruptions?
3. With NERC expanding its registration criteria for GO, how should companies approach the integration of new assets or changes in ownership to ensure seamless compliance? What are the key considerations to keep in mind?
4. How do supply chain issues impact the timely implementation of these new standards, particularly in terms of retrofitting existing or new installs? What proactive measures can be taken to mitigate potential risks?
5. What are some of the most challenging aspects of testing and verification in the context of these new standards, especially when dealing with a mix of new and retrofitted IBR? How do you ensure that testing protocols are robust enough to meet compliance requirements without introducing unnecessary complexity or delays?

Welcome to the Standards Committee and NERC Ride-through Technical Conference Day 1

Safety Briefing

NERC Antitrust Compliance Guidelines and Commission Staff Disclaimer

Welcome and Opening Remarks

Rob Manning – NERC Board of Trustees
Mark Lauby – NERC
David Ortiz – FERC

Technical Conference Overview - Standards Committee

Todd Bennett – AEC

RELIABILITY | RESILIENCE | SECURITY

Summary Review of Milestone 2 and Order 901

Jamie Calderon - Manager, Standards Development
Standards Committee & NERC Ride-through Technical Conference
September 4, 2024

Order 901 Summary

- FERC Order 901
  - October 2023
  - 4 Milestones through November 2026
  - IBR related performance issues
  - Leverage existing guidance where possible

Order 901 Summary

- IBR Data Sharing
- IBR Model Validation
- IBR Planning and Operational Studies
- IBR Performance Requirements

185 FERC ¶ 61,042
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM22-12-000; Order No. 901]

Reliability Standards to Address Inverter-Based Resources

(Issued October 19, 2023)

AGENCY: Federal Energy Regulatory Commission

ACTION: Final rule

SUMMARY: The Federal Energy Regulatory Commission (Commission) is directing the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization, to develop new or modified Reliability Standards that address reliability gaps related to inverter-based resources in the following areas: data sharing; model validation; planning and operational studies; and performance requirements. The Commission is also directing NERC to submit to the Commission an informational filing within 90 days of the issuance of this final rule that includes a detailed, comprehensive standards development plan providing that all new or modified Reliability Standards necessary to address the inverter-based resource-related reliability gaps identified in this final rule be submitted to the Commission by November 4, 2026.

DATES: This rule is effective **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**

[E-1-RM22-12-000 | Federal Energy Regulatory Commission (ferc.gov)]()

Order 901 Summary

Registered IBRs

- *Bulk-Power System connected IBRs registered with NERC for compliance purposes*

Unregistered IBRs

- *Bulk-Power System connected IBRs not registered with NERC for compliance purposes*

"IBR-DER"

- *Distribution connected IBRs that in the aggregate have a material impact on the Bulk-Power System*

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

FERC Order 901 Milestones

1 COMPLETED JANUARY 2024

Order No. 901 Work Plan submission

2 DUE NOVEMBER 4, 2024

Standards development and filing to address performance requirements and post-performance validations for Registered IBRs

3 DUE NOVEMBER 4, 2025

Development and filing of Reliability Standards to address data sharing and model validation for all IBRs

4 DUE NOVEMBER 4, 2026

Development and filing of Reliability Standards to address use of performance data in Operational and Planning studies

Project 2021-04
Modifications to PRC-002 - Phase II

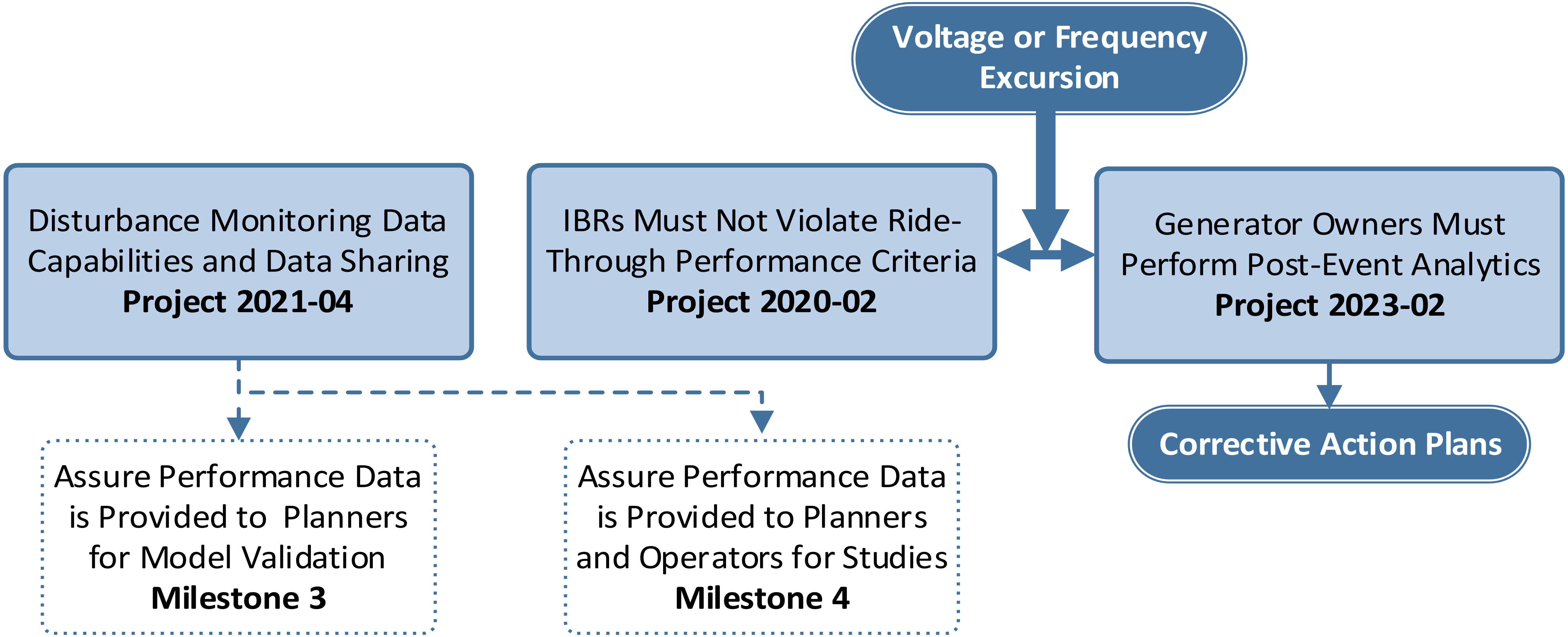
- New Standard: PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
- Data needed by all 901 related Standards
- Requires installation of equipment - phased-in through 2030
- Share data on request

Project 2020-02
PRC-024 (Generator Ride-through)

- New Standard: PRC-029-1 Frequency and Voltage Ride-through Requirements for Inverter-Based Resources
- Establish capability-based ride-through criteria
- Establish performance-based ride-through criteria

- New Standard: PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation
- Analysis of performance during a disturbance
- Triggers what is evaluated for ride-through performance

Milestone 2 Summary



Questions and Answers

Communication

Quick Reference Guide: IBR Registration Initiative

August 2024

As part of its *Inverter-Based Resource Strategy*, NERC is dedicated to identifying and addressing challenges associated with inverter-based resources (IBR) as the penetration of these resources continues to increase. ERO Enterprise assessments identified a reliability gap associated with the increasing integration of IBRs as part of the grid in which a significant level of bulk power system-connected IBR owners and operators are not yet required to register with NERC or adhere to its Reliability Standards.

In response, FERC issued an order in 2022 directing NERC to identify and register owners and operators of currently unregistered bulk power system-connected IBRs. Working closely with industry and stakeholders, NERC is executing a FERC-approved work plan to achieve the identification and registration directive by 2026. Resources are also posted on the Registration page of the NERC website.

Key Activities

- NERC's Board of Trustees approved proposed Rules of Procedure revisions on February 22 and filed them with FERC on March 19.
- FERC issued an order approving the Rules of Procedure revisions, subject to submitting a compliance filing, on June 27.
- NERC published its Q2 2024 Quarterly Update on July 11.
- NEW NERC submitted its quarterly work plan update to FERC on August 9.

IBR Registration Milestones

Phase 1: May 2023–May 2024

- Complete Rules of Procedure revisions and approvals
- Commence Category 2 GO and GOP candidate outreach and education (e.g., through trade organizations)

Phase 2: May 2024–May 2025

- Complete identification of Category 2 GO and GOP candidates
- Continue Category 2 GO and GOP candidate outreach and education (e.g., quarterly updates, webinars, workshops, etc.)

Phase 3: May 2025–May 2026

- Complete registration of Category 2 GO and GOP candidates thereafter subject to applicable NERC Reliability Standards
- Conduct specific Category 2 GO and GOP outreach and education (e.g., quarterly updates, webinars, workshops, etc.)

Available Resources

- NERC Registration Page
- Standards Under Development Page | FERC Order No. 901 Milestone 2 Summary
- Q1 2024 Update | Q2 2024 Update
- IBR Webinar Series and FAQs
- Quick Reference Guide: Candidate for Registration
- Quick Reference Guide: Inverter-Based Resource Activities
- Learn about NERC and Join the E-ISAC

LEARN MORE ABOUT NERC AND THE E-ISAC

Review of Voltage and Frequency Ride-through Criteria in PRC-029-1

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

Xiaoyu (Shawn) Wang, Chair (Enel North America)
Husam Al-Hadidi, Vice Chair (Manitoba Hydro

NERC Ride-through Technical Conference
September 04, 2024

Drafting Team Roster

	Name	Entity
Chair	Xiaoyu (Shawn) Wang	Enel North America
Vice Chair	Husam Al-Hadidi	Manitoba Hydro
Members	Ebrahim Rahimi	California ISO
	John B. Anderson	Xcel Energy
	Johnny C. Carlisle	Southern Company Services, Inc.
	Robert J. O'Keefe	American Electric Power
	Rajat Majumder	Invenergy
	Alex Pollock	RES
	Ebrahim Rahimi	California ISO
	Fabio Rodriguez	Duke Energy
	Kenneth Silver	8minute Solar Energy
	Ovidiu Vasilachi	Independent Electricity System Operator (IESO)
	John Zong	Electric Power Engineers
NERC Staff	Jamie Calderon	North American Electric Reliability Corporation

Project 2020-02 SAR1

- **Title**: Revision of relevant Reliability Standards to include applicability of transmission-connected dynamic reactive resources
- **Date Submitted**: Feb 24, 2020 (Revised on February 3, 2022)

Project 2020-02 SAR2

- **Title**: **Generator Ride-through Standard (PRC-024-03 Replacement)**
- **Date Submitted**: April 28, 2022 (revised March 31, 2023)
- **Industry Need:**
- Based on the ERO Enterprise analyzing over 10 disturbances reports highlighting key findings and recommendations
  - A widespread loss of generating resources – solar PV, wind, synchronous generation, and battery energy storage systems (BESS)
  - Multiple IBR experience abnormally tripping, ceasing current injection, or reducing power output with control interactions.
  - The unexpected loss of widespread generating assets poses a significant risk to BPS reliability.
- The existing PRC-024-3 is an equipment settings standard focused solely on voltage and frequency protection and is inadequate to address the IBR performance issues
- The proposed standards project will address this known reliability risk with a more suitable performance-based standard that ensures generating resource ride-through performance for expected or planned BPS disturbances

Project 2020-02 SDT Approach

- Modify PRC-024-3 to retain the Reliability Standard as a protection-based standard, applicable only to synchronous generators, synchronous condensers, and Type 1 and Type 2 wind turbines
- Create a new Reliability Standard (PRC-029-1) to address inverter-based resource (IBR) disturbance ride-through performance criteria
- Coincide with ride-through requirements of IEEE standards but structure to follow language from FERC Order No. 901, which states that "NERC has the discretion to consider during its standards development process whether and how to reference IEEE standards in the new or modified Reliability Standards"

Project 2020-02 after 1st Comment Period

- The comment period and initial ballot for the first draft: 3/27/2024 – 4/27/2024
- The first draft failed the initial ballot and received ~200 pages of comments from different stakeholders
- The drafting team went through a series of meetings to address all the comments in May and early June, including an in-person meeting and dedicated meetings with specific stakeholders, e.g., EPRI
- The second comment period on Draft 2: 6/18/2024 – 7/8/2024
- The drafting team went through a series of meetings to address all the comments in July and issued Draft 3: 7/22/2024 – 8/12/2024
- PRC-024-4 has passed ballot
- Draft 3 of PRC-029-1 failed to pass ballot
- On August 15, the NERC Board of Trustees invoked Rule 321

A. Introduction

1. **Title:** **Frequency and Voltage Ride-through Requirements for Inverter-Based Resources**
2. **Number:** **PRC-029-1**
3. **Purpose:** To ensure that ~~Inverter-Based Resources (~~IBR~~s)~~ ~~adhere to~~ Ride-through ~~requirements as expected~~ to support the Bulk Power System (BPS) during and after defined frequency and voltage excursions.
4. **Applicability:**

4.1 Functional Entities:

4.1.1. Generator Owner

~~4.1.2. Transmission Owner[1]~~

4.2 Facilities:

4.2.1. The Elements associated with (1) Bulk Electric System (BES) IBRs ~~inverter-based resources[2]~~ and (2) Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

~~4.2.2. IBR Registration Criteria~~

Project 2020-02
Draft Language PRC-029-1

R1. Each Generator Owner ~~or Transmission Owner~~ shall ensure the design and operation is such that each ~~facility~~ IBR meet or exceed ~~adheres to~~ Ride-through requirements, in accordance with the "must Ride-through[3] zone" as specified in Attachment 1, except for the following: *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

- The ~~facility~~ IBR needed to electrically disconnect in order to clear a fault; or
- The voltage at the high side of the main power transformer[4] went outside an accepted~~A documented equipment~~ hardware limitation, ~~exists~~ in accordance with Requirement R4; or
- The instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer and is initiated by a non-fault switching event on the transmission system[5]; or
- The Volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

M1. Each Generator Owner ~~and Transmission Owner~~shall have evidence ~~of dynamic simulations, studies, or other evidence~~ to demonstrate the design of each facility will adhere to Ride-through requirements, as specified in Requirement R1. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner ~~and Transmission Owner~~ shall ~~have~~ retain evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) to demonstrate that the operation of each ~~facility~~ IBR did adhere to Ride-through requirements, as specified in Requirement R1. If the Generator Owner ~~and Transmission Owner~~ choose to utilize Ride-through exemptions that occur within the "must Ride-through zone" and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner ~~and Transmission Owner~~ shall also ~~have~~ retain evidence of actual disturbance monitoring (i.e. Sequence of Event Recorder, Dynamic Disturbance Recorder, and Fault Recorder) data to demonstrate that the ~~facility~~ IBR failed to Ride-through during a phase jump of greater than or equal to 25 electrical degrees, and documentation from their Transmission Planner, Reliability Coordinator, Planning Coordinator, or Transmission Operator that a non-fault initiated switching event occurred.

Project 2020-02
Draft Language PRC-029-1

R2. Each Generator Owner ~~or Transmission Owner~~ shall ensure the design and operation is such that -the voltage performance for each ~~facility~~ IBR adheres to the following during a voltage excursion, unless a documented ~~equipment~~ hardware limitation

2.1. While the voltage at the high-side of the main power transformer[6] remains within the continuous operation region as specified in Attachment 1, each ~~facility~~ IBR shall:

2.1.1 Continue to deliver the pre-disturbance level of ~~active~~ Real ~~p~~Power or available ~~active~~ Real ~~p~~Power[7], whichever is less.[8]

2.1.2 Continue to deliver R~~r~~eactive ~~p~~Power up to its ~~r~~Reactive ~~p~~Power limit and according to its controller settings.

2.1.3 Prioritize Real Power or Reactive Power ~~If the facility cannot deliver both active and reactive power due to a current limit or reactive power limit,~~ when the voltage is less than~~below~~ 0.95 per unit, the voltage is ~~and still~~ within the continuous operation region, and the IBR cannot deliver both Real Power and Reactive Power due to a current limit, unless otherwise specified through other mechanisms by an associated~~then preference shall be given to active or reactive power according to requirements if required by the~~ Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Project 2020-02
Draft Language PRC-029-1

2.2. While voltage at the high-side of the main power transformer is within the mandatory operation region as specified in Attachment 1, each IBR shall exchange current, up to the maximum capability to provide voltage support, on the affected phases during both symmetrical and asymmetrical voltage disturbances, either under[9]:

- Reactive P~~p~~ower priority by default; or
- ~~Active~~ Real ~~p~~Power priority if required through other mechanisms by an~~the~~ associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Project 2020-02
Draft Language PRC-029-1

2.3. While voltage at the high-side of the main power transformer is within the permissive operation region, as specified in Attachment 1, each ~~facility~~ IBR may operate in current block mode if necessary to avoid tripping. Otherwise, each ~~facility~~ IBR shall follow the requirements for the mandatory operation region in Requirement R2.2.

2.3.1 If a ~~facility~~ IBR enters current block mode, it shall restart current exchange in less than or equal to five cycles of positive sequence voltage returning to a continuous operation region or mandatory operation region.

2.4. Each ~~facility~~ IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable high voltage thresholds and time durations in its response as voltage recovers from the mandatory or permissive operation regions to the continuous operation region.

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2.5. Each ~~facility~~ IBR shall restore ~~active~~Real ~~p~~Power output to the pre-disturbance or available level[10] (whichever is lesser) within 1.0 second when the voltage at the high-side of the main power transformer returns from the mandatory operation region or permissive operation region (including operating in current block mode) to the continuous operation region, as specified in Attachment 1, unless ~~the~~ an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires a lower post-disturbance ~~active~~ Real ~~p~~Power level requirement or requires a different post-disturbance ~~active~~ Real ~~p~~Power restoration time through other mechanisms.[11]

R3. Each Generator Owner ~~or Transmission Owner~~ shall ensure the design and operation is such that each ~~facility~~ IBR meets or exceeds~~adheres to~~ Ride-through requirements during a frequency excursion event whereby the System frequency remains within the "must Ride-through zone" according to Attachment 2 and the absolute rate of change of frequency (RoCoF)[12] ~~–~~magnitude is less than or equal to 5 Hz/second. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

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R4. Each Generator Owner ~~and Transmission Owner~~ identifying an ~~facility~~ IBR that is in-service by the effective date of PRC-029-1, has known hardware limitations that prevent the ~~facility~~ IBR from meeting voltage Ride-through criteria as detailed in Requirements R1 and R2, and requires an exemption from specific voltage Ride-through criteria shall:[13] *Lower] [Time Horizon: Long-term Planning]*

4.1. Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1. This documentation shall include:

4.1.1 Identifying information of the IBR (name, facility #~~, other~~);

4.1.2 Which aspects of voltage ride-through requirements that the IBR would be unable to meet and the capability of the ~~equipment~~ hardware due to the limitation;

4.1.3 Identify the specific piece(s) of ~~equipment~~ hardware causing the limitation;

4.1.4 Supporting technical documentation verifying the limitation is due to hardware that needs to be physically replaced or that the limitation cannot be removed by software updates or setting changes, and;

4.1.5 Information regarding any plans to remedy the ~~equipment~~ hardware limitation (such as an estimated date).

4.2. Provide a copy of the information detailed in Requirement R4.1 to the ~~applicable~~ associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and ~~to~~ the ~~Regional Entity~~CEA no later than 12 months following the effective date of PRC-029-1.

4.2.1 Any response to additional information requested by the ~~applicable~~ associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and ~~to~~ the ~~Regional Entity~~CEA shall be provided back to the requestor within 90 days of the request.

~~4.2.1~~**4.2.2** Provide a copy of the acceptance of an hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s).[14]

4.3. Each Generator Owner ~~and Transmission Owner~~ with a previously ~~submitted~~ accepted limitation~~request for exemption~~ that replace the ~~equipment~~hardware causing the limitation shall document and communicate such an hardware ~~equipment~~ change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the hardware ~~equipment~~ change.

4.3.1 When existing ~~equipment~~ hardware causing the limitation is replaced, the exemption for that Ride-through criteria no longer applies.

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Table 1: Voltage Ride-Through Requirements for AC-Connected Wind ~~Facility~~IBR [15]

Voltage (per unit)[16]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[17]	N/A
~~≤ 1.20 and~~ ≥ 1.10	Mandatory Operation Region	1.0
~~≤ 1.10 and~~ > 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90 ~~and ≥ 0.70~~	Mandatory Operation Region	3.00
< 0.70 ~~and ≥ 0.50~~	Mandatory O	
< 0.50 ~~and ≥ 0.25~~	Mandatory O	
< 0.25 ~~and ≥ 0.10~~	Mandatory O	
< 0.10	Permissive O	

Table 222: Voltage Ride-Through Requirements for All Other ~~Inverter-based Resource Facilities~~IBR

Voltage (per unit)[18]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[19]	N/A
~~≤ 1.20 and~~ > 1.10	Mandatory Operation Region	1.0
~~≤ 1.10 and~~ > 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90 ~~and ≥ 0.70~~	Mandatory Operation Region	6.00
< 0.70 ~~and ≥ 0.50~~	Mandatory Operation Region	3.00
< 0.50 ~~and ≥ 0.25~~	Mandatory Operation Region	1.20
< 0.25 ~~and ≥ 0.10~~	Mandatory Operation Region	0.32
< 0.10	Permissive Operation Region	0.32

Attachment 2: Frequency Ride-Through Criteria

Table 3: Frequency Ride-Through Capability Requirements

System Frequency (Hz)	Minimum Ride-Through Time (sec)
>~~≥~~ 64.0	May trip
~~< 64 and~~ ≥ 61.8	6
~~< 61.8 and~~ ≥ 61.5	299
~~< 61.5 and~~ > 61.2	660
≤ 61.2 and >~~<~~ 58.8	Continuous
≤ 58.8 ~~and < 58.8~~	660
≤~~<~~ 58.5 ~~and ≥ 57~~	299
≤~~<~~ 57.0 ~~and ≥ 56~~	6
< 56.0	May trip

- Relevant information
  - Project page
- Contact information
  - Jamie Calderon: Jamie.Calderon@nerc.net
  - Xiaoyu (Shawn) Wang: xiaoyu.wang@enel.com
  - Husam Al-Hadidi: halhadidi@hydro.mb.ca

Questions and Answers

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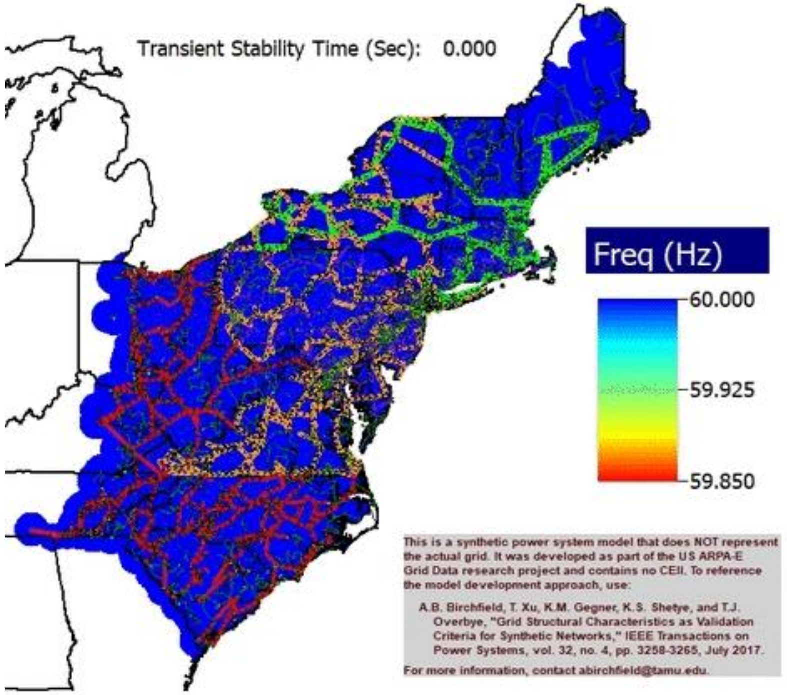
Review of Voltage and Frequency Ride Through

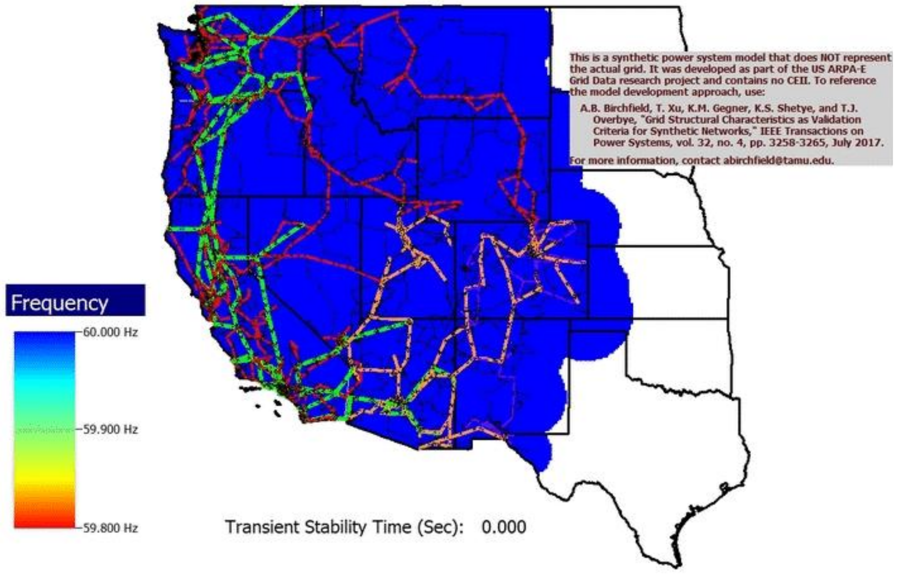
Alex Shattuck, Senior Engineer
NERC Ride-through Technical Conference
September 04, 2024

Why do we need Ride-through?

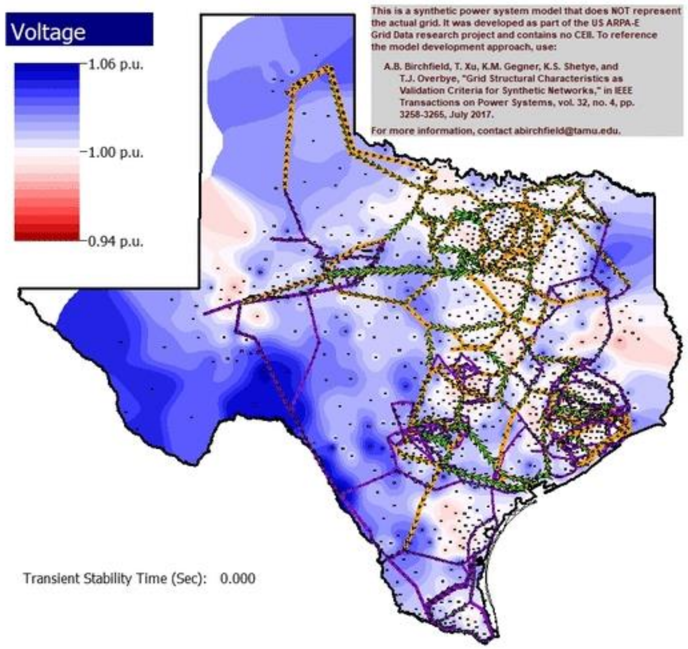
- Unexpected events happen often on the bulk power system
  - These events cause varied deviations from nominal in system voltage and frequency
    - Not all unexpected events cause major deviations, but the bulk power system must be prepared to perform reliably when major events occur
- NERC must create effective and efficient criteria to reduce reliability risks



25,000 Bus Synthetic Grid - Northeastern United States (tamu.edu)



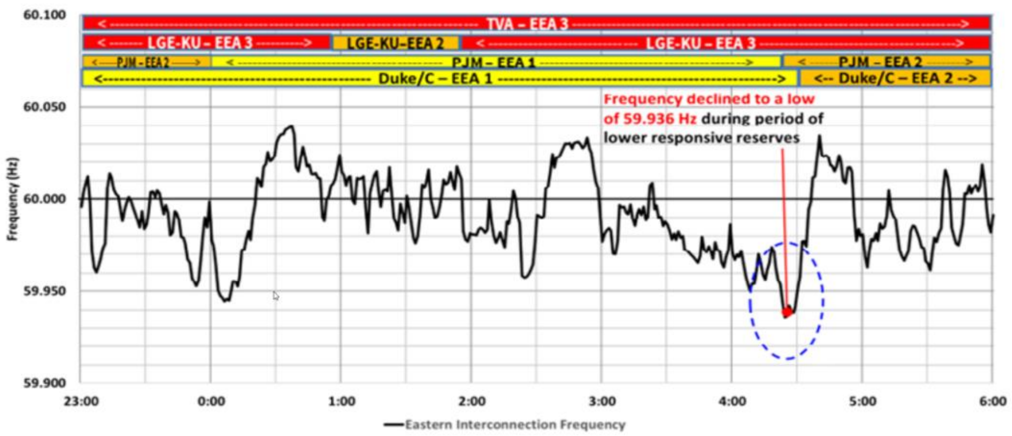
10000 Bus Synthetic Grid - Western United States (tamu.edu)



2000 Bus Synthetic Grid - Texas (tamu.edu)

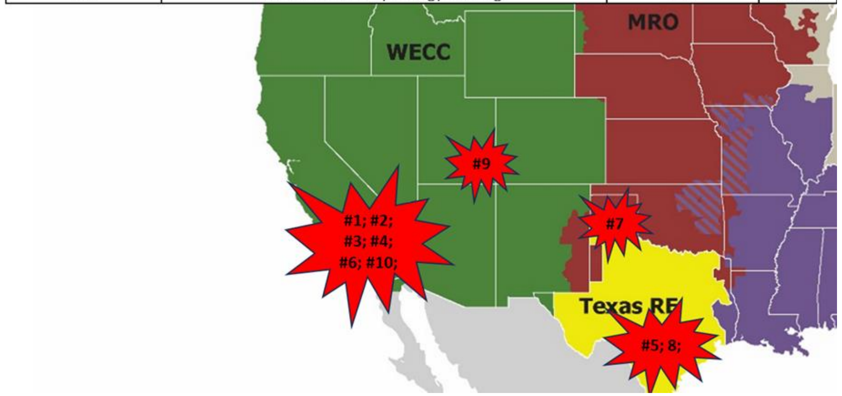
Summary of Observed Major Events

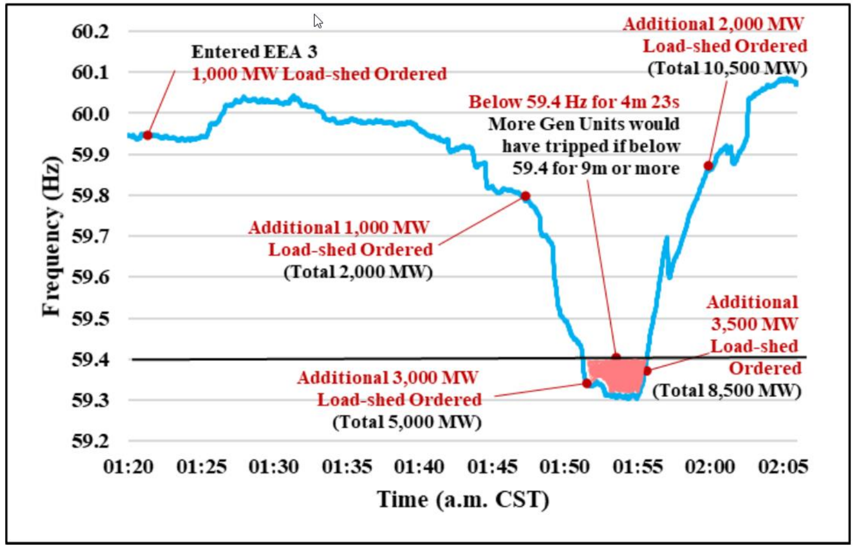
- 10 published major disturbance reports published since 2016 with an approximate total of 15,000 MW
- Numerous wind-related events in ERCOT area that did not trigger event reports
- Winter storms Uri and Elliot stressed system frequency



Eastern Interconnection System Frequency | Winter Storm Elliott Report

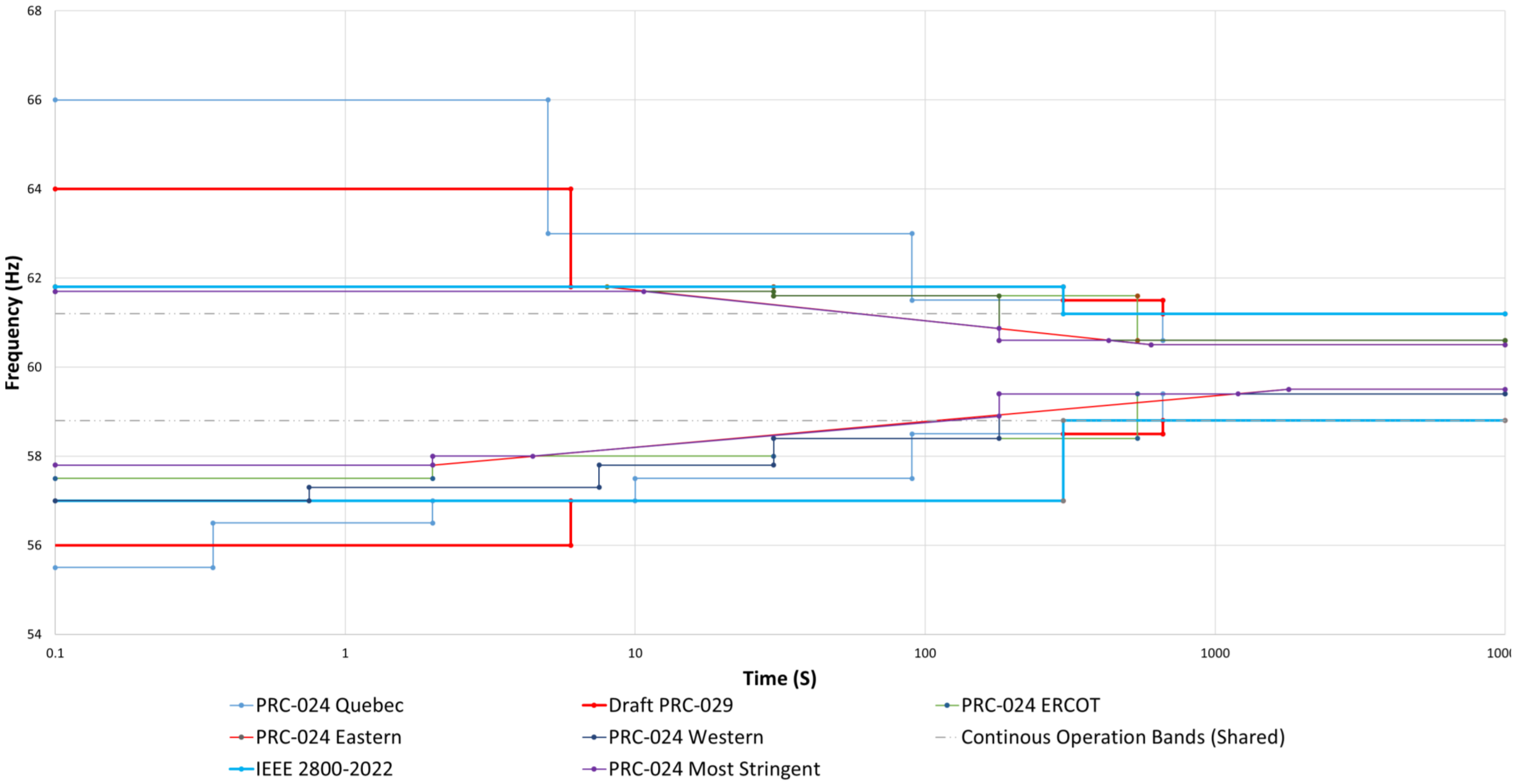
Reference Number	Disturbance	IBR Reduced (MW)	Year
#1	Blue Cut Fire	1,753	2016
#2	Canyon 2 Fire	1,619	2017
#3	Angeles Forest & Palmdale Roost	1,588	2018
#4	San Fernando	1,205	2020
#5	2021 Odessa	1,112	2021
#6	Victorville & Tumbleweed & Windhub & Lytle Creek Fire	2,464	2021
#7	Panhandle Wind	1,222	2022
#8	2022 Odessa	1,711	2022
#9	Southwest Utah	921	2022
#10	California Battery Energy Strorage	906	2023



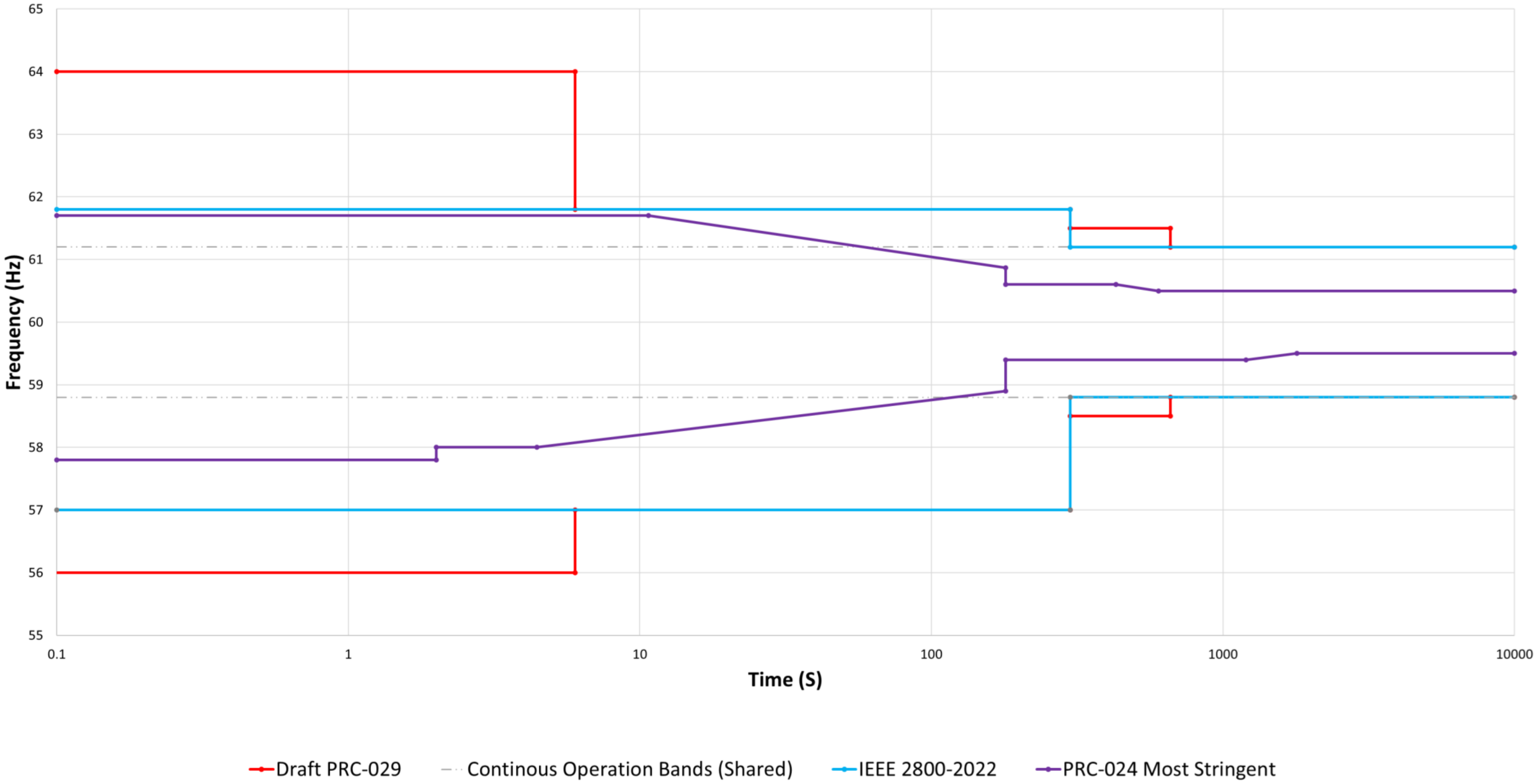


ERCOT System Frequency |The February 2021 Cold Weather Outages in Texas and the South Central United States

Comparing Frequency Criteria

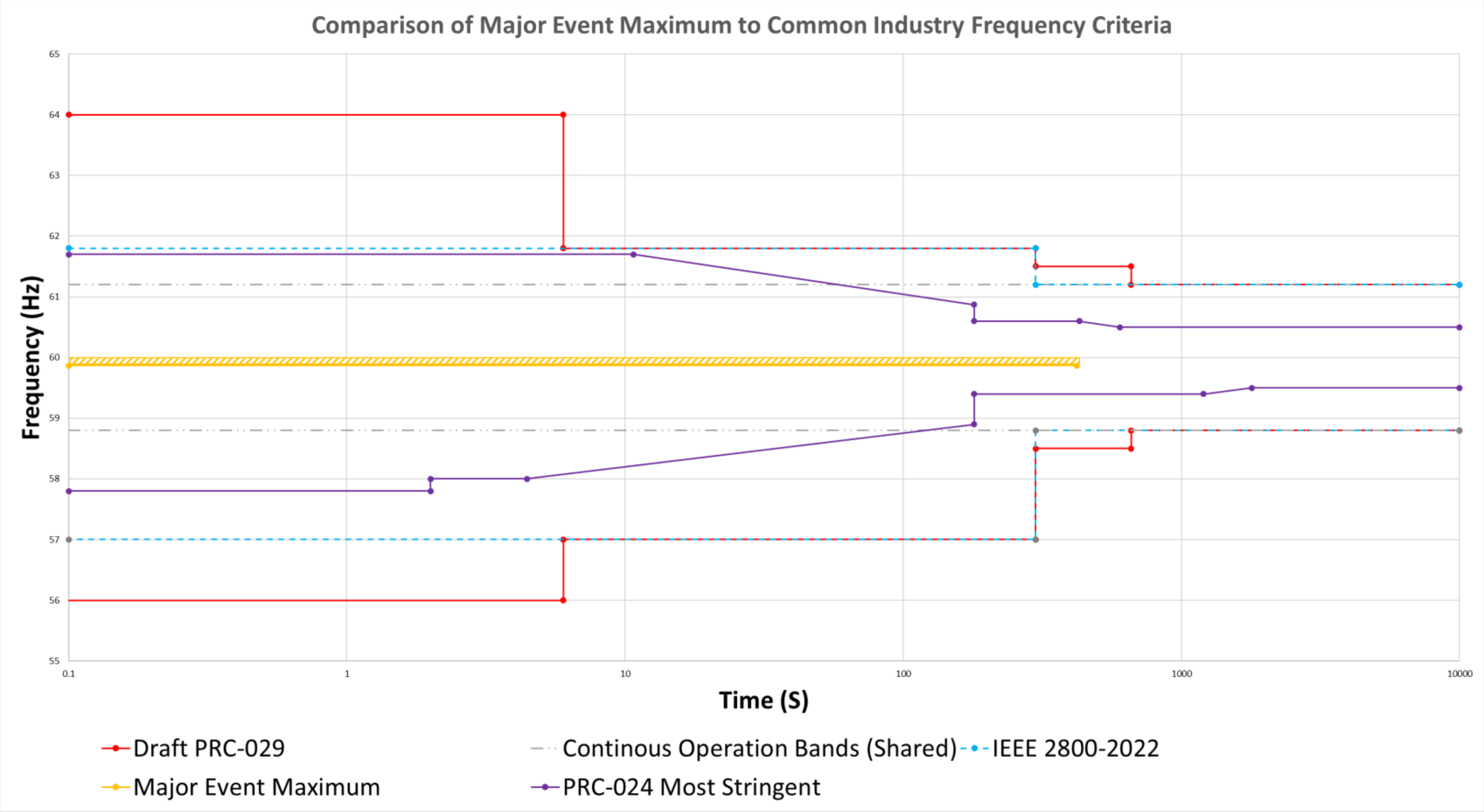


Comparing Frequency Criteria



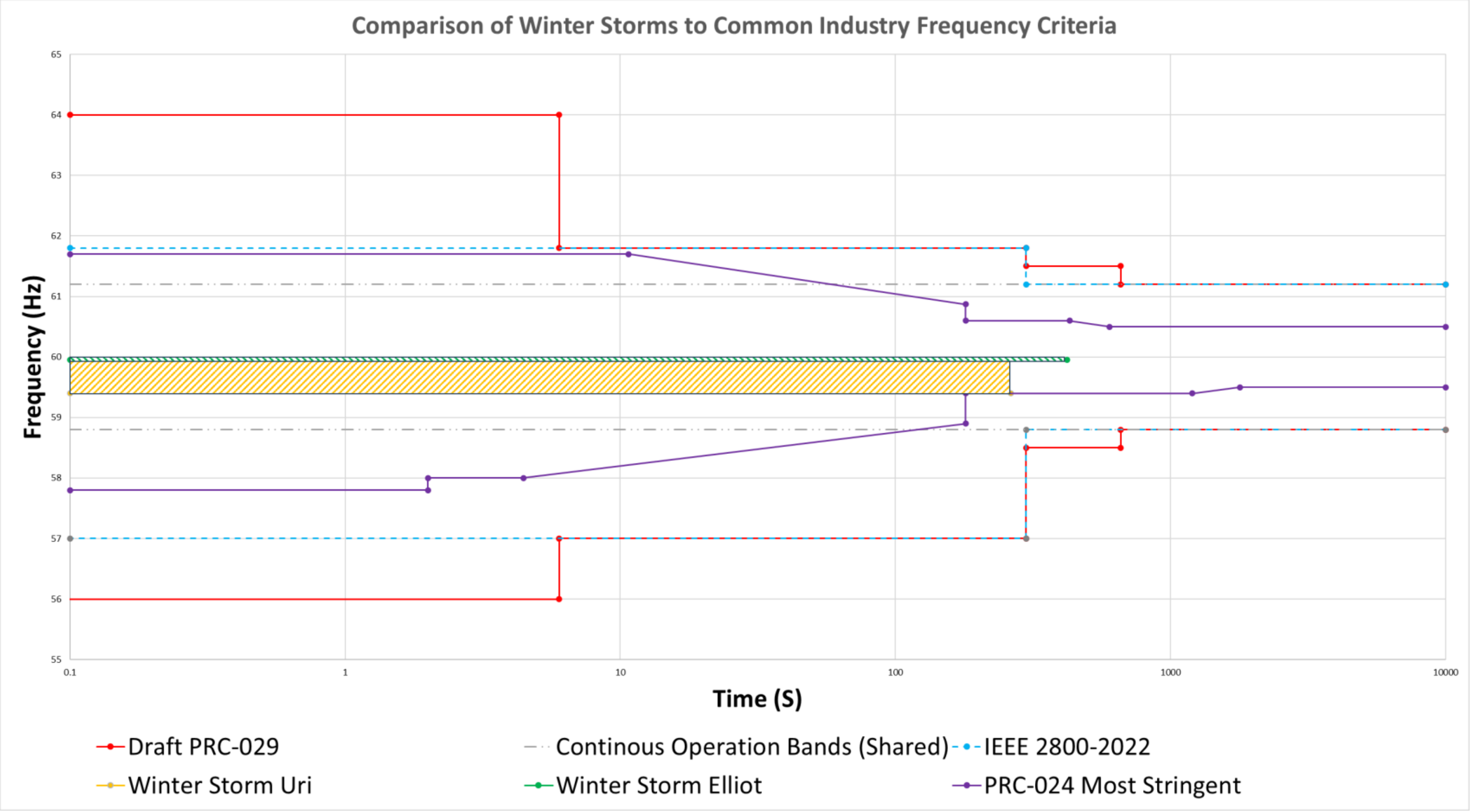
Comparing Major Events to Ride-through Criteria

- All events in published major event reports saw deviations within continuous operation bands in draft PRC-029 and IEEE 2800-2022
- Nearly all frequency-related tripping was due to the use of instantaneous measurements



Comparing Winter Storms to Ride-through Criteria

- Winter storms resulted in significantly more severe frequency deviations
- Winter storm Uri frequency deviation touches PRC-024 criteria but is far from draft PRC-029 and IEEE 2800-2022 criteria



Summary of Disturbance Observations

- Analyzed major events and both winter storm Uri and Elliot resulted in frequency deviations **within the continuous operation bands detailed in the draft PRC-029 and IEEE 2800-2022**
- Currently **no "benchmark event"** for frequency and voltage criteria to be based on
- **Branching Paths:** Set protection settings as wide as possible to maximize ride-through capability **– or –** determine *reasonable* criteria that will ensure BPS reliability

NERC's Published Recommendations for Ride-Through

- From the March 14, 2023 Level 2 Alert: Inverter-Based Resource Performance Issues
  - *Expand AC voltage protection settings as widely as possible within the inverter equipment capability. Eliminate or minimize the use of inverter instantaneous AC voltage tripping (e.g., zero or near-zero3 time delay using instantaneous peak measurements)*
  - *Inverter frequency protection should be set based on equipment capability. Frequency protection should operate on a filtered frequency measurement over a time window. Eliminate or minimize the use of inverter instantaneous frequency tripping.*
    - Notes 2-3 on Table 3 of draft PRC-029 Attachment 2 address the filtered measurement performance issue
- These recommendations have been repeated in numerous major event reports

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Balance is Needed

Bulk Power System Needs

- Maximum Ride-through Capability
- Effective and efficient reduction of risks

Effective and Efficient Criteria

Technical Capabilities

- Significant lead time necessary to design new equipment
- Hardware Limitations at legacy IBRs
- Diminishing returns at capability extremes

How Can New Equipment Meet Criteria?

- **Criteria need to be reasonable** when compared to current and future equipment capabilities
- If criteria are outside of current equipment capabilities, **sufficient lead time is necessary** for manufacturers to make necessary design changes and come to market
- Sufficient time is necessary for **testing** to ensure equipment can meet proposed criteria
- **Manufacturer input and evidence is crucial**

What if Criteria Cannot Be Met by Legacy Equipment?

Manufacturer input and detailed documentation is critical for determining solutions

- Software-based protection parameter changes
- Small hardware-based retrofits of equipment
- Significant hardware-based retrofit or replacement

Are Exemptions Necessary?

- Some amount of legacy IBR may not be able to meet newly proposed criteria
  - Software-based upgrades are a simple path towards compliance with newly proposed criteria
- Additional considerations are needed when software-based upgrades are not sufficient
- Exemptions can allow legacy equipment to remain connected to the BPS while maximizing their capabilities and sharing this data with affected entities
  - Efficacy of exemptions is dependent on:
    - Sufficient documentation detailing a hardware-based limitation
    - Sufficient documentation that software-based protection settings are set at the maximum capability of the equipment
    - Review of the provided documentation to determine the level of risk associated with the documented maximum
  - **Blanket exemptions** without detailed documentation is **not a sufficient solution**

Quantifying Risks for Legacy IBR

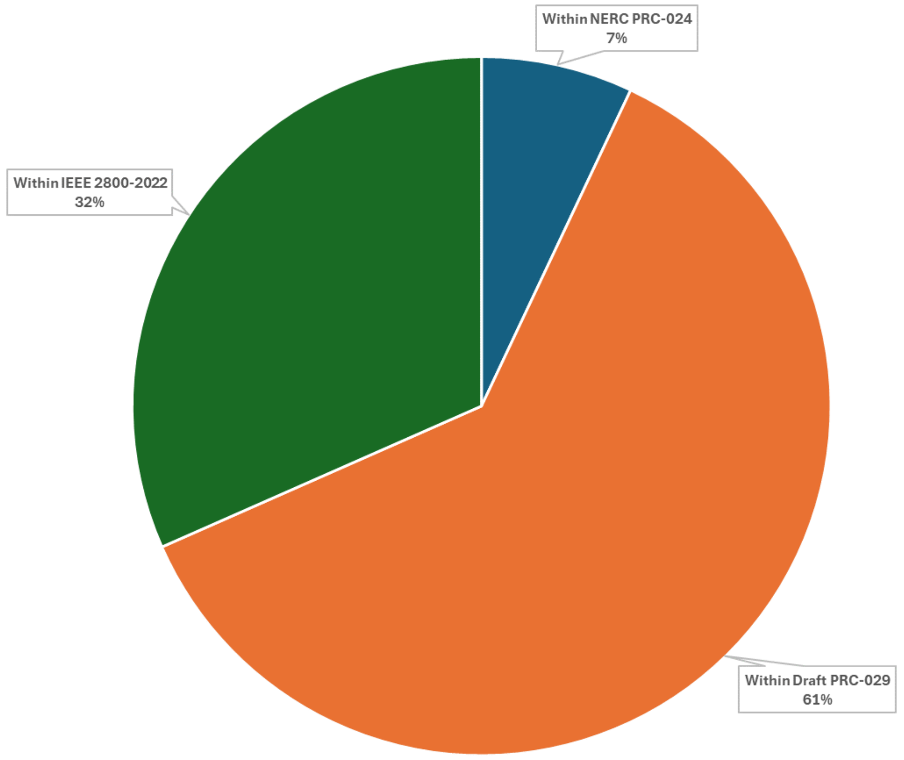
- Data from Level 2 Alert on IBR Performance includes all BPS-connected solar PV and BESS
- Reported data shows significant number of resources with possible software-based solutions
- Reported settings at maximum capability allow the risks of different criteria to be quantified

Table 2.1: Protection Settings Based on Maximum Equipment Capability

Ride-Through Protection Type	Yes	No	Percent Yes
High Voltage	617	1,399	30.61%
Low Voltage	722	1,209	37.39%
High Frequency	376	931	28.77%
Low Frequency	476	1,021	31.80%
Total	2,191	4,560	32.45%

NERC_Inverter-Based_Resource_Performance_Issues_Public_Report_2023

Frequency Protection Settings Reported to be set at Maximum Capabilities



Manufacturer Challenges

- **Challenges for new IBR equipment:**
  - Deciding which criteria to design for
  - Procuring testing locations to show compliance
  - Long lead times for design changes driven by changing requirements
  - Ride-through capabilities can become cost prohibitive at extremes

- **Challenges for Legacy IBR Equipment:**
  - Hardware-based limitations exist
  - Software-based solutions may still not meet new criteria
  - Legacy equipment was tested in accordance with applicable requirements at the time of interconnection
    - True capability is "unknown" and retesting legacy equipment may not be feasible
  - Coordinating and implementing effective and efficient solutions can be difficult

Industry Challenges

- **Challenges for new IBR equipment:**
  - Deciding which equipment will be needed to meet new requirements
  - Obtaining evidence that equipment can meet new requirements
  - Communicating technical details necessary to provide sufficient model and facility data

- **Challenges for Legacy IBR Equipment:**
  - How to manage facilities with hardware-based limitations
  - Assessing the feasibility of software-based solutions can be difficult
  - Sometimes challenging to obtain objective capability-based information
  - Coordinating and implementing effective and efficient solutions can be difficult

Key Takeaways

- NERC has **analyzed over 15,000 MW** of unexpected disturbances with very few IBR tripping due to frequency criteria exceedance
  - All analyzed events caused frequency deviations **within continuous operation** bands of draft PRC-029 and IEEE 2800-2022
- NERC recommends to **maximize ride-through** capability
- **Validated documentation on limitations is crucial** for efficient and effective criteria but has proven **difficult to obtain**
- **Manufacturer input on true capabilities of legacy and new equipment is critical**

Questions and Answers

Panel Discussion: Original Equipment Manufacturer Perspectives on Voltage and Frequency Ride-through Criteria

Thomas Schmidt Grau – Vestas
Thierry Ngassa – Power Electronics
Scott Karpiel – SMA
Dinesh Pattabiraman – TMEIC
Samir Dahal – Siemens Energy
Arne Koerber – GE Vernova

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Panel Discussion with Q&A: Addressing the Challenges of Voltage and Frequency Ride-through Criteria

Mark Lauby – NERC
Manish Patel – EPRI
Todd Chwialkowski – EDF
Andy Hoke – NREL
Michael Goggin – Grid Strategies LLC

Slido Polling: Voltage and Frequency Ride-through Criteria

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Parking Lot

Day 1 Wrap-up

Sue Kelly – NERC Board of Trustees

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Welcome to the Standards Committee and NERC Ride-through Technical Conference Day 2

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NERC Antitrust Compliance Guidelines and Commission Staff Disclaimer

Recap of Day 1 and Introduction to Day 2

Todd Bennett – AEC
Soo Jin Kim – NERC

Panel Discussion: Discussion on Frequency Ride-Through Exemptions in PRC-029-1

Moderators: Charles Yeung – SPP and Alex Shattuck – NERC

Panelist: Howard Gugel – NERC, Dane Rogers – OGE, Jason MacDowell – GE Vernova, Mark Ahlstrom – NextEra

Outlining Objectives of a Ride-through Definition

Joel Anthes, P.E. – 2020-02 Drafting Team Member
NERC Ride-through Technical Conference
September 5, 2024

Why is PRC-029-1 Including a Definition of Ride-through?

The Project 2020-02 SAR Generator Ride-through Standard (PRC-024-3 Replacement) – submitted April 28, 2022(revised March 31, 2023), includes additions to the NERC Glossary of Terms and directs the drafting team to "define the term ride-through, as necessary".

The drafting team for PRC-030-1 – "Unexpected Inverter-Based Resource Event Mitigation", under Project 2023-02, requested that the drafting team for PRC-029-1 include a definition for Ride-Through. This was necessary to link their requirement 2 reference to "Document the facility's Ride-through performance…"

Definition Overview

Drafting Team's Goals in Defining Ride-through Were:

- Create a stand-alone definition that could be included in the NERC Glossary that was not tied to or limited by the PRC-029-1 standard.
- Create a definition that could be used within other standards, namely PRC-030-1, to allow them to reference IBR Ride-through performance requirements.

Definition Overview

Drafting Team's Goals in Defining Ride-through Were Not:

- To create an additional quantitative performance requirement(s) merely by defining the term Ride-through.
- To define the IBR performance necessary to support system reliability (this is instead defined under Requirements 1-4 of PRC-029-1).

Proposed Definition

Draft 2 Definition: Remaining connected, synchronized with the Transmission System, and continuing to operate in response to System conditions through the time-frame of a System Disturbance.

Draft 3 Definition: The entire plant/facility remaining connected to the Bulk Power System and continuing in its entirety to operate through System Disturbances.

- Removed “synchronized with”, in response to System conditions”
- Added “entire” and “in its entirety”
- Replaced “Transmission System” with “Bulk Power System”

Proposed Definition

Draft 3 Definition: The entire plant/facility remaining connected to the Bulk Power System and continuing in its entirety to operate through System Disturbances.

Uses approved NERC Glossary terms:

Bulk-Power System	(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. (Note that the terms "Bulk-Power System" or "Bulk Power System" shall have the same meaning.)
Disturbance	1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

IEEE 2800-2022 Definition

IEEE 2800 Ride-through Definition: *Ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified.*

Drafting Team Comments:

- “Ability to withstand” may not be clearly construed to mean “remaining connected”
- “inside defined limits” is a reference to requirements in a standard, is unnecessary to describe the essence of what it means to ride through, and results in the definition not being stand-alone
- “as specified” is again a reference to requirements in a standard that is unnecessary to describe the essence of what it means to ride through, and results in the definition not being stand-alone

Other Proposed Definitions

- **Other Ride-through Definition 1:** *Ability to withstand System disturbances inside defined limits and to continue operating as specified.*
  - Very similar to IEEE 2800-2022 definition.
- **Other Ride-through Definition 2:** *Ability to withstand voltage or frequency Disturbances within defined regulatory limits remaining connected, synchronized with the Transmission System, and continuing to operate.*
- Merges aspects of IEEE and SDT draft 2 definitions; what is meant by "regulatory limits" is not clear.

Other Proposed Definitions

- **Other Ride-through Definition 3:** *Facilities, including all individual dispersed power producing resources, remaining connected to the electric system and continuing to operate in a manner that supports grid reliability throughout a System Disturbance, including the period of recovery back to a normal operating condition.*
  - Seems more a system level definition than facility level; the phrase "in a manner that supports grid reliability" makes it dependent on what a standard or a description found elsewhere would describe; last phrase underlined is viewed as equivalent to "operate through System Disturbances"

Other Proposed Definitions

- **Other Ride-through Definition 4:** *Remaining connected, synchronized with the Transmission System, and continuing to operate by delivering power in response to System conditions through the time-frame of a System Disturbance.*
  - Very similar to Draft 2 definition adding only "by delivering power" which will not always be the case with batteries in charging or idle modes
- **Other Ride-through Definition 5:** *The entire plant/facility remaining connected to the Bulk Power System and continuing to operate through System Disturbances.*
  - Similar to Draft 3 definition only removing "in its entirety"

Other Proposed Definitions

- **Other Ride-through Definition 6:** *The plant/facility remaining connected to the Bulk Power System and continuing to operate through System Disturbances as defined in applicable reliability standards*
  - Removing "entirety" and "in its entirety" could make it possible to qualify partial tripping as ride-through; adding "as defined in applicable reliability standards" makes definition dependent on what such standards would describe
- **Other Ride-through Definition 7:** *The entire plant/facility remaining connected to the Bulk Power System, and continuing in its entirety to operate as specified through the time-frame of System Disturbances.*
  - Draft 3 definition with "as specified" which makes it dependent on a standard and inserting "the time-frame of" which is pretty similar to "through" [System Disturbances]

Other Proposed Definitions

- **Other Ride-through Definition 8:** *The entire plant/facility remaining connected and continuing to operate through the duration of a frequency or voltage Disturbance in its entirety, from its start to the return to pre-disturbance conditions.*
  - Essentially the same as SDT draft 3 with non-substantive changes and removal of "Bulk Power System"
- **Other Ride-through Definition 9:** *The entire plant/facility remaining connected to the Bulk Power System and continuing in its entirety to operate as specified through System Disturbances inside defined limits.*
  - Same as SDT draft 3 definition adding "as specified" and "inside defined limits" which makes it dependent (not stand-alone)

Other Proposed Definitions

- **Other Ride-through Definition 10:** *The entire plant/facility (including its dispersed power producing inverters) remaining connected to the electric system and continuing in its entirety to operate in a manner that supports grid reliability through a System Disturbance, including the period of recovery back to a normal operating condition".*
  - Adding "in a manner that supports grid reliability" makes it dependent on what a standard or a description found elsewhere would describe; substituting "electric system" for "Bulk Power System" counters a draft 3 revision to satisfy other commenters that distribution is off limits to NERC; other additions viewed as non-substantive

Other Proposed Definitions

- **Other Ride-through Definition 11:** *The plant/facility shall remain connected and in service, maintaining the pre-disturbance equipment configuration in operation, throughout the entirety of the system disturbance and recovery.*
  - Removing "entirety" and "in its entirety" could make it possible to qualify partial tripping as ride-through; other changes viewed as non-substantive.

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Questions and Answers

Slido Polling: Gathering Stakeholder Input on Revised Definitions

Moderator: Amy Casuscelli – Xcel Energy

Detailed Review of Milestone 2 Implementation Plans

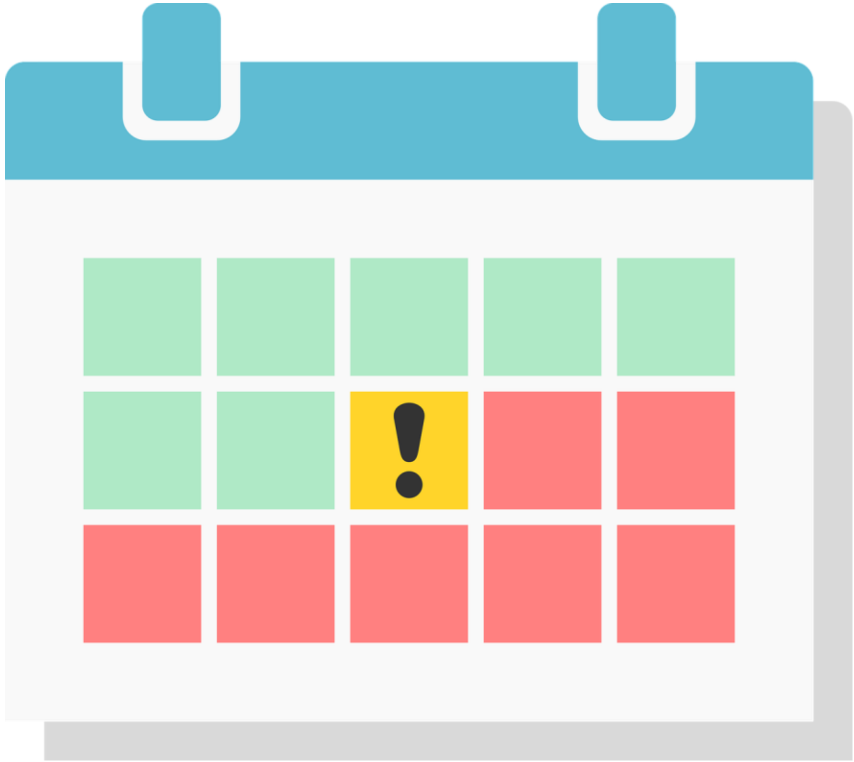
Jamie Calderon - Manager, Standards Development
Standards Committee & NERC Ride-through Technical Conference
September 5, 2024

What is an Implementation Plan?

- Created For:
  - New/Modified Reliability Standards
  - Retiring Reliability Standards
  - New/Modified Definitions
- Ensures no overlap or gap in time between versions

Key Terms and Sections of an IP

- "Effective Date"
  - Specific Date
  - Time Period after approval by governmental authority
- "Retirement Date"
  - Immediately Prior
- General Considerations
- Other Standard specific



Phased-In Implementation

- Often used to avoid everything all at once
- Milestones beginning after "Effective Date"
- Examples:
  - Percentage of Facilities
  - Requirement R1 and then later R2
- Assists Entities in

- New Standard: PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
- **Shall become effective on the first day of the first calendar quarter after the effective date of the Applicable Governmental Authority's order approving the standard**

- **Phased-In Implementation for:**
  - Existing BES Inverter-Based Resources (in commercial operation on or before the effective date),
  - New BES Inverter-Based Resources
  - Existing Non-BES Inverter-Based Resources
  - New Non-BES Inverter-Based Resources

- **Existing BES IBR:** 50% of IBR within three years of the effective date of PRC-028-1 and 100% of BES IBR by January 1, 2030
- **New BES IBR:** BES IBRs entering commercial operation after July 1, 2025, but on or before October 1, 2026, entities shall comply with Requirements R1 through R7 by October 1, 2026

- **Existing Non-BES IBR:** 100% January 1, 2030.
- **Existing Non-BES IBR:** within 15 calendar months following the effective date of the standard or the commercial operation date, whichever is later.
- **Process for Compliance Extensions**

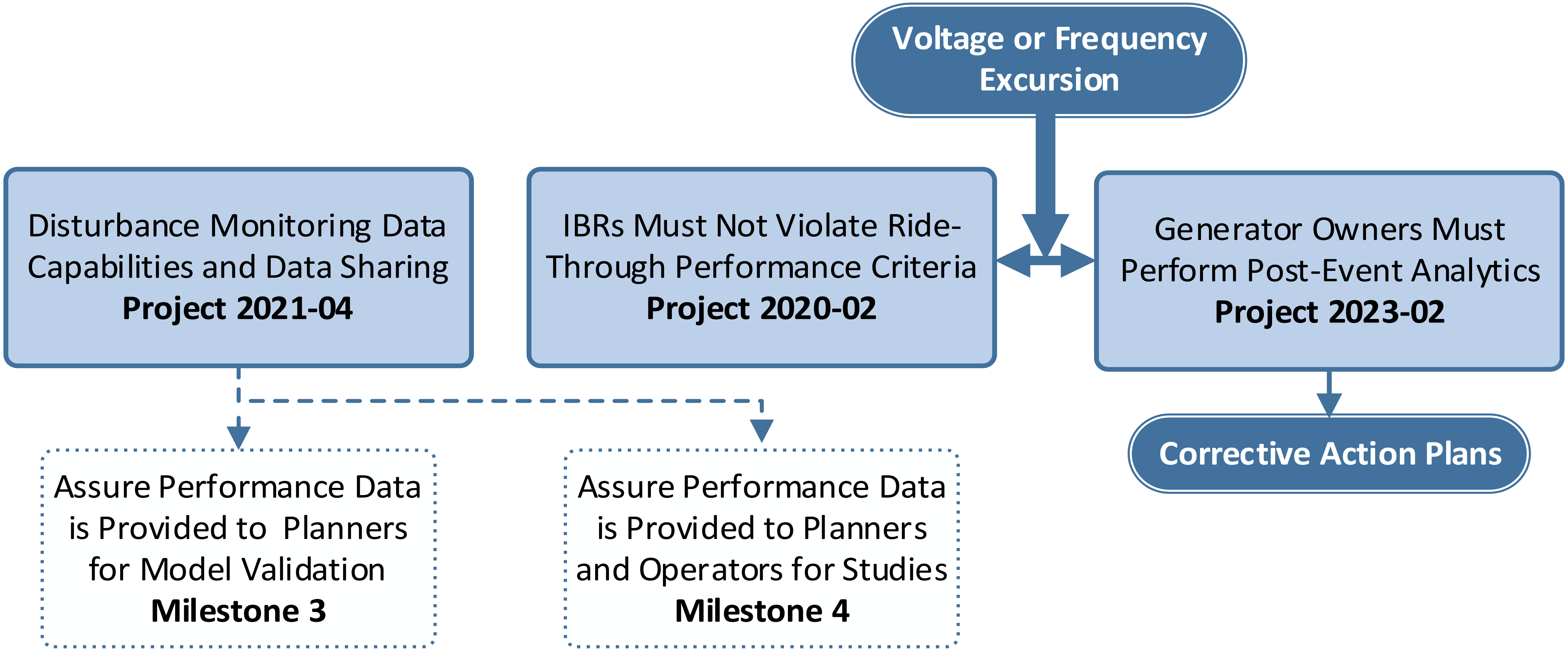
- New Standard: PRC-029-1 Frequency and Voltage Ride-through Requirements for Inverter-Based Resources
- **Shall become effective twelve months after the effective date of the applicable governmental authority's order approving the standard**

- Capability-based ride-through criteria
  - BES IBR: the effective date of the standard.
  - Non-BES IBR: later of January 1, 2027; or the effective date of the standard.
- Performance-based ride-through criteria
  - BES IBR and Non-BES IBR: Align with PRC-028 Implementation Plan dates

- New Standard: PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation
- IP revised in current draft posted for formal comment. Currently under ballot and cannot discuss during Q&A.
- Removed performance-based and capability-based language

- Later of 1) the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority’s order approving the standard; or 2) the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority’s order approving Reliability Standard PRC-029-1,
- Aligns with PRC-029

Aligned Implementation



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Questions and Answers

Panel Discussion: Strategizing Implementation Plans and Effective Dates

Moderator: Charles Yeung – SPP and Jamie Calderon – NERC

Panelist: Howard Gugel – NERC, Sam Hake – AES, Manish Patel – EPRI, Rhonda Jones – Invenergy

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Afternoon Break
15 Minutes

Slido Polling: Voltage and Frequency Ride-through Criteria

Moderator: Amy Casuscelli – Xcel Energy and NERC Staff

Slido Polling: Consensus on Implementation Plans

Moderator: Amy Casuscelli (Xcel Energy)

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Slido Polling: The Proposed Path Forward

Moderator: Amy Casuscelli – Xcel Energy and NERC Staff

Closing Remarks and Next Steps

Sue Kelly – NERC Board of Trustees and Todd Bennett – AEC

Transcript of **Technical Conference Day 1**

Wednesday, September 4, 2024

Conference for North American Electric Reliability Corporation

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
(NERC)

Standards Committee and NERC Ride-through
Technical Conference

Wednesday, September 4, 2024
9:06 a.m.

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AGENDA

AGENDA (continued)

AGENDA (continued)

P R O C E E D I N G S

MS. WASHINGTON: All right. Good morning. Thank you for attending the NERC Ride-through Technical Conference. As a reminder to all participants, this webinar is public and is being recorded. The registration information was posted on the NERC website and widely distributed. Speakers in the room should keep in mind that the listening audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders. Should you wish to ask a question during today's webinar, please use the Q&A feature in the bottom right corner of your screen.

Please note that there will also be a Slido during today's conference. It's NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates or that might appear to violate the antitrust laws. Any NERC participant that is uncertain about the legal ramification of a particular course of conduct, or who has doubts or concerns about whether or not the NERC's antitrust compliance policy is implicated in any situation should consult NERC's general counsel, Sonya Rocha.

At this time, I will turn the webinar over to NERC Board of Trustee, Mr. Rod Manning.

MR. MANNING: That's working. Good morning.

PARTICIPANTS: Good morning.

MR. MANNING: Welcome, and thank you for being here. Many are here in the room. Many more, I think, are here on the call. I struggle this morning to describe this meeting. I was having a conversation with someone and I would say, it's going to be fun, and then I'd stop and say, well, perhaps it's not going to be fun. It's going to be exciting. Well, perhaps it's not going to be exciting. I think where I ended up with, it's going to be hard. I think that's fair. What we're doing is going to be hard. Perhaps it's evolutionary, I think, certainly evolutionary what we're doing today and tomorrow. Revolutionary? Maybe. Could be revolutionary.

We see the transformation of the grid -- we all see the transformation of the grid. It's happening all around us, whether we choose to technically shape the outcome or not. Sometimes I think if we choose to not take any action, the grid will transform itself anyway, but we all know that condition causes the latter to be less than the former, and I don't think any of us agree that that's acceptable, at least from a reliability perspective. None of us find this workable solution, I think going forward, and all of us agree that we need to act with contemplative intention or you wouldn't be here today. We need to think about where we're going with this.

I feel like today we meet head on one of our very first transformative decisions. I recently read the book, "The Last Days of Night," written by Graham Moore, and it's a story of Westinghouse versus Edison, a story of invention versus industrialization perhaps. It's a story of AC versus D.C. It's a great read. I highly recommend it if you're part of our industry. It's fascinating. Not everyone would find it fun or exciting. Some might find it hard, but I think if you've got any history in our business, you would really enjoy reading about the early days of the AC versus DC.

And as I was thinking about what to talk about this morning, I really thought about, you know, what we are considering over the next couple of days is a giant step towards rendering those prior AC/DC arguments, perhaps not irrelevant, but maybe extraneous. We're taking a big step forward, and it hasn't been easy to get to this point, and it won't be easy to find a pathway forward today and tomorrow. What we are going to do is going to be difficult. It's going to be hard. The good news is we do hard. We have a track record of embracing hard things and wrestling them to the ground.

So as we are about to tackle this hard task, it seems to me that there are three things that frame our pathway forward. First of all, the risk is sufficient.

The need for voltage and frequency Ride-through criteria has been demonstrated over and again. The incidents are becoming ever more complex. The potential impacts are becoming ever more predictable. To continue without addressing this issue really causes us to fail to address and remediate the appropriate risk. The risk is sufficient to take action. Second, the technology is sufficient. Now, we will hear more about that today and perhaps tomorrow, but it seems clear that what we want to do can be done with technology that is available. Finally, the time that we have taken so far is sufficient. We have moved through the full measure of process and engagement. We have heard from all front, we have taken information from all comers, and now the time has come for us to stop arguing and do something. We began studying this issue, believe it or not, in 2016, eight years ago. The time has come.

So there you have it. The risk is sufficient. The technology is sufficient. The time is sufficient. What remains is to just get it done. Hard or easy becomes irrelevant. All that remains relevant really is to chart a pathway forward, the pathway that sees us confidently step into the future of reliability. So that's why I'm here today. I suspect that's why most of you are here today, and I thank you for being here. I thank you for the skills that you bring to the table. I thank you for your engagement, for your knowledge. I thank you for your presence here in the room or on the phone. I thank you for your willingness to seek a solution where those who've gone before us have failed to find a solution. We're going to need all of your skills in the next 30 hours or so. Certainly what we're doing is evolutionary, revolutionary perhaps. The next few hours will write this story for us, so I thank you for being here, I thank you for your time, and I thank you for getting it done. Mark.

MR. LAUBY: Ditto. David?

(Laughter.)

MR. LAUBY: So anyway, good morning, everybody, and that's a wonderful setup for the -- today's meeting. I did want to kind of think about how we got here. And so I talked to my old friend, Faraday, who, in 1980 -- in 1830s, excuse me -- came up with kind of the first machine with a -- with a magnet and a spinning disc, and, you know, we've been making improvements to that from the beginning, DC machines, AC machines. I always want to start thinking about that group, AC/DC, but let's not go there, and the whole system, of course, being synchronized was a big, big chore. And we -- it was really all about managing mechanical energy, you know, taking mechanical energy and moving it, transporting it to where we need to use it, of course, then transforming that to actual work.

And when we think about NERC and all the activities that we all work on, it's all about avoiding what we call the evil three, which is the instability, islanding, and controlled -- uncontrolled cascading. In fact, Steinmetz has been quoted saying that we created the largest machine that people have ever built in the -- in the world with the interconnected systems. But, you know, it's kind of like when I'm listening to my 1970s and 1980s tunes on the radio and my daughters say, that's before the turn of the century, dad, because that's not where we are today.

You know, we have a significantly new way of generating electrons or exciting electrons, let's put it that way, because they don't really flow. They kind of get excited and bounce off each other. And not all of the transformation here is between mechanical energy to electrical energy, but rather, we're really managing the kind of the characteristics of a new type of resource in this case, solar panels, but even wind, though, at least wind has some mechanical energy. So there's no surprise that, you know, we have some kind of disagreements on the way forward here. It's a place that we haven't been before, and nd it disrupts a lot of the technology. It disrupts a lot of the -- kind of the rules of thumb that we're used to using and really kind of calls into question some of our fundamental assumptions, so, you know, Ride-through, of course, is just an important part of being able to go through the system events and avoid the evil three, right? And so it's certainly an important characteristic that the system should have to maintain the reliable operation of the system.

And we now have high-speed inverters that can really do whatever we want them to do, and we're trying to some -- in some cases try to at least mimic the characteristics that we need. But they have other characteristics, too, that we can take advantage of, and, in fact, they're critically important to the green transformation of the system, and we see inverters everywhere. Heck, my refrigerator's been out for like four months because I can't get inverters to fix it because they're putting them in cars and they're putting them in solar panels, and I don't have refrigeration. Well, anyway, that's another story. We should buy a new refrigerator, I guess. But this -- it's also a part of our -- now our inverter base loads. So how are we going to manage those? How are they going to sustain the reliable operation of the system? All this comes into question. So we are really here on a cutting edge, and, you know, there just -- there's a lot obviously that has to be done, and we really stand at the inflection point of this new system.

And I really -- to, you know, Rob's point here, thank you for all the work that you've done to date, how much work you're going to have to do to get us to that next step, an important, I think, inflection point in our industry. So as I mentioned before, Steinmetz was talking about the largest machine that was ever built. We're building the largest computer now, and it will be one that will be fast moving and can provide services that perhaps we never even dreamed of and be a more reliable, more resilient, more secure, and we need everybody's help to get there. So thank you. With that, next, I'll ask David to provide opening remarks.

DAVID ORTIZ: Thanks, Mark. Thanks, Rob. It's hard to hear yourself, right, stand right in front of the speaker. So maybe I'll start with a joke, I think. I had a teacher once that said that AC power was invented just so people would have to learn trigonometry.

(Laughter.)

DAVID ORTIZ: So my name is David Ortiz. I'm the director of the Office of Electric Reliability at FERC. I want to thank Rob for motivating the conference, Mark for his kind of technical insight. I'm here to provide just kind of a little bit of an overview on some of the process concerns and what our role is here, especially since a lot of what's happening is in response to a

FERC order. It's important to note, obviously, that I'm a FERC staff member, and these are my opinions and not those of the Commission or any individual commissioner.

As you know, Section 215 of the Federal Power Act describes the roles of FERC and NERC. And most specifically, the way it works is that those who run the system, those who build the system, those who plan the system, the ones with the expertise are the ones who develop the standards, you know, with NERC's assistance, and then those are submitted to the Commission for approval and/or directed modification, and that's an important role. And so really, the job is in your hands fundamentally, and that's the way it's been structured in the statute. NERC's rules permit extraordinary action in certain cases, especially with respect to a FERC directive, and that's the reason why we're here because of action that the NERC Board took a few weeks ago.

And then I want to note that, you know, I'm here and several other FERC staff members are here, and our role today is fundamentally as observers. We're going to have a really big bite at the apple in November after you complete your work here and NERC submits the standards to us. But the instigating action that kind of brought us here was Order Number 901, which the Commission issued in October 2023, and that directed NERC to develop reliability standards for inverter-based resources in four areas: IBR performance, data and information, model validation, and then planning and operational studies.

We gave NERC a really tight timeline for this, and, you know, we're not necessarily sorry about that, but it definitely is really pushing the limits of the processes that NERC has, and we appreciate NERC and all of you working toward those. You know, specifically, we ask that you -- that in NERC, finish the standards and submit those at the Commission for approval on a rolling time -- on a rolling basis in three years. And, you know, as you know, even a standard for which there is essentially no disagreement, just some details to work out, typically takes about a year to develop. And so to actually solve complex technical problems and submit to us a standard is a -- is a pretty high bar, and we understand that. And so, you know, to Rob's point, yes, this is a difficult task that we gave you, and to a certain extent, it's just beginning. You know, perhaps this will be a great conference and this will be a model for the next sets of standards, who knows, but, you know, there's still a lot of work to be done, and I want to thank Jamie for managing the whole endeavor. I'm surprised that she still has hair.

And I want to kind of address one thing with respect to Order Number 901. I know that within the discussions that you've been having specifically about this standard, but also about the standards which passed recently, there's been a lot of discussion about the order and language in the order. As a Commission staff member, and especially as an engineer and not as an attorney, I'm not in a position here to interpret the order, but one thing that I can say is that the way the Commission works is that it -- the Commission makes its decisions based upon a record. And that record that we -- that the Commission had in last October was what it -- is what it used in order to make the decisions in Order Number 901. If there is new information that's brought to bear that would cause the Commission to reconsider that, then that's something that the Commission has done in the past, and I presume it would be open to do -- to do in this case.

So for example, perhaps there's quantitative data about the capabilities of various inverter-based resources of various vintages, or perhaps there's some operations and planning studies that indicate that certain performance characteristics actually help to maintain reliability as opposed to others that have been proposed already. The more specific information that NERC -- that you provide and that you help NERC to submit in the record, the easier it will be for the Commission to make a decision regarding this standard and any standard, you know. This is just the way that the standards process works and the way that the Commission works.

The record, though, that we had indicates that this is something that needs to be done. As Rob said, this is something that NERC has been investigating since 2016 after the Blue Cut Fire disturbance and the -- and not only is this a -- an eight-year-old problem, at least, right? It's one that is -- there's a wave that's coming that's tremendously important for us to get a handle on. And that's the fact that, you know, EIA projects now, and it perhaps -- and this was last year -- perhaps it's changed already -- that fully half of U.S. electricity will be -- electricity will be produced by inverter-based resources by the end of the decade, right? So, you know, not only has it been a long time, but there isn't any time to waste.

So I appreciate everybody getting together, looking forward to just observing a productive conversation. Anybody wants to chat with me or staff, we're happy to have that conversation, but really, this is your time to do work, and we're just here to help. So thank you so much, and have a good day.

(Applause.)

MR. BENNETT: Okay. Good morning, everybody. Okay. So thank you for all the opening remarks from our -- from our three speakers that kind of help set the tone for the meeting today. So now my name's Todd Bennett. I'm chair of the NERC Standards Committee. I'm kind of here to walk through the objectives of the agenda, but, Mark, just so you know, it looks like we're going to do this through some high-voltage rock and roll today, so there's your AC/DC reference.

So first of all, thank you to everybody that has been involved in putting this together, so the panelists that volunteered, the NERC staff that helped coordinate a lot of the agenda, the meeting space, this location, all of that, as well as the Standards Committee members, so thank you to all the committee members. For those that may not know, that is a voluntary role, so this is in addition to their day job at their respective companies. So I want to say thank you to each one of those and what they've done to make this successful so far.

So let's kick this off, and, you know, our agenda, kind of just to review the agenda, I saw kind of three main objectives that came through the agenda upon my initial review. So the first one is very specifically on communication. So one of the objectives of this agenda was to communicate the technical issues and to level set on those throughout industry, OEMs and any of the other roles that we all play in industry. So we all come here, you know, and we're all going to learn something today probably just a little bit.

But then secondly, another objective is collaboration. And so some of the items that really spoke to collaboration on the agenda have to do with the panel discussions. So over the next couple days, there's several panel discussions on various technical issues with this project. In support of those panel discussions, I will say that Standards Committee and NERC did receive multiple sets of very, very technical comment and feedback. So first of all, we welcome that, that it was in great support of this Technical Conference. I do want to assure those that submitted those, that those have been reviewed by NERC Standards Committee, and the information contained therein has been used to formulate some questions for the panel sessions, so thank you for that. That really helps frame the -- frame the discussion.

So one thing you should be prepared for is there is a finite amount of time for each one of these panel discussions, so there's between 45 minutes or an hour or so. And there is a preset amount of questions, so there's about 10 minutes allotted for each question to make it through. Panelists may find that there's an opportunity to kind of build on some of the panelist responses before each subsequent panelist. That may be the case. If not, I don't want to, you know, frame your responses at all, but you may be able to make the most of our time and kind of build on some of the responses from before. So just be cognizant of there is kind of a time constraint on some of the panel discussions.

And then lastly, consensus. So maybe that's the main objective of this Technical Conference is industry consensus. How do we move forward? It's time to move forward. How do we take some steps forward? So we do have a tool that will help with that. I believe it was mentioned earlier, Slido. I've used it before. This is the app or the technology or the mechanism that will be implemented to issue some polling of the industry after some of the panel discussions. It's also a way to provide feedback during some of the panel discussions, so that is the chat mechanism for this conference. So you won't find that functionality in

Webex. It'll come through Slido. So there's more to come on that. There's more discussions -- or sorry -- more instructions on how to participate and the appropriate times to participate, so pay attention. More to come on that.

And with that, I don't think I have anything else to share. That's my agenda review. And I believe Jamie is ready to review the summary of the FERC Order 901 and Milestone 2, so we'll let her get set up here, and I believe she's going to go through a presentation with us.

MS. CALDERON: All right. Want to do a quick level set, so we're going to get really deep into the technical details during this conference which is good, it's why we're here, but we don't want to lose the forest from the trees type conversation, so let's take a step back. We're going to go all the way back in our time machine to October of 2023. David Ortiz opened it up for us, given us the -- kind of a little bit of the background on FERC Order 901 coming out.

So next slide, please.

Quick summary for everyone. The order came out in

October 2023. There are four milestones all the way through November of 2026, and they address a wide spectrum of IBR performance-related issues. Everyone here, I'm sure, is familiar with some of the performance issues that are in question. A lot of it has to do with making sure we have an accurate way that we represent them within models, that we're including them within studies appropriately, and that we're also just getting the data to begin with. So we want to be able to leverage the existing standards. It's not always a good idea to just come in and do a tear-down/rebuild when you don't have to, but we want to make sure that we're being able to implement meaningful changes within the standards. So if it requires a little bit of a step-back where a new standard, as we've seen with the IBR performance-related standards, that's one avenue to go to, and the team felt it was appropriate during this -- during these discussions this last year.

Next slide, please.

So as indicated, there are really four main issues of this data sharing assuring that the data is available. We're talking about high-speed sequence event recorders, fault recorder data, stuff that has not been traditionally needed at conventional generation. So those needed to be installed, and we needed to ensure that the requirements were in place that required the sharing of that data to those who needed it, either for modeling or for doing those studies, or just for situational awareness, being able to monitor the onsite impacts and making sure that that was visible.

There's model validation, ensuring that not just once it gets thrown into the model, hasn't been validated. We're looking at also verifying during the interconnection process has the model accurately represented what was as built, if there was design changes that happened during the initial interconnection studies and we're moving into the post commercial operation, and it's not operating the way it was designed to as the way the model practices and simulation, then there's an issue there. So we want to make sure that we're building an effective model validation throughout, planning and operational studies that leverage that. And performance requirements were listed last, but, of course, we get to those first.

So next slide, please.

Another thing about Order 901 was that it references three different types of IBRs. So just to make sure that we're level setting on what those IBRs are, registered IBRs for the purposes of FERC Order 901, that is any IBR that is going to be registered as either, what we're referring to as Category 1 or Category 2. Now, the distinction between registered and unregistered IBR has to do with the earlier FERC Order 2022 that required the expansion of requiring new IBR generator owners to become registered and into the NERC regulatory environment. We're looking at aggregated IBR of 20 MVA and up connected at 60 kV. So this is an expansion of the IBR and generator owners. A lot more people coming on board.

In that original Order 2022, it was focused on registered and unregistered within that context. For FERC Order 901, "registered" encompasses both of those. So to be clear, that unregistered IBR is really focused on the not going to be registered, not part of the

Category 2 GO/GOPs that would be potentially interconnected at the transmission level. That would be looking at aggregated sets of IBR that will not have generator owners, but will be the responsibility of transmission owners to aggregate and incorporate into their models.

IBR/DR, similar conversation only at the DR level. So you're looking at the distribution level IBR, potentially rooftop, not to be confused with having individual model data for each of those, but the aggregated impacts to the distribution provider and ensuring that the distribution provider has at least some estimation for capturing those within their models and knowing the limits of their estimation. So if there's particular issues with acquiring the data, acquiring specific data, that that distribution-level data is at least estimated and being able to continue to be developed over time.

How we get that aggregation is going to be a continual conversation, but it's actually not part of the performance requirements in Milestone 2. The only ones that are identified within Milestone 2 are those registered IBRs that are going to be part of the Category 1/Category 2 generator owners. Those would be interconnected at 60 kV and up with the aggregation of 20 MVA and up.

Next slide, please.

Okay. So we are in the first stages of this. Again, it hasn't even been a year since the order came out. So putting this in context, you know, we had to go through some of the motions here. Rule 321 was something that we absolutely did not want to pursue if not needed, and it was determined to be needed in this case. We needed to make sure that we were having a really frank conversation on some of these issues and just an open technical conversation. But we don't want to lose sight of the fact that we have two additional milestones that will equally be exhaustive in terms of scope of work and the amount of time that it's going to be taking to get this together. We don't want to find ourselves in a similar position next year.

So this presentation and this whole conference, while we're looking at -- specifically at Ride-through and the very specific aspects, I know we want to get into exemptions and criteria discussions, but we don't want to lose sight of the fact that there's still a lot more that we need to be able to do and within the next two years. So the scope of work for November 4th, we look to be on track. We only have one standard that hasn't passed, and I think we'll be able to get to a solution at the end of this conference.

Next slide.

Okay. So just to break up the three standards. First Project 2021-04 at a new standard. Again, we decided to break out the IBR versus the conventional generation. So where we had PRC-02 that was focused on, you know, capturing this information, we've created a new standard. This Drafting Team decided to put forward PRC-028, looking at disturbance monitoring and reporting requirements for IBR. This is installing new sequence event recorders, fault-recorded data, and making sure all of that information is being provided through those requirements. So there might be a trigger, such as a request from a planner or operator, for that information. There's a small period of time that that data is just be -- required to be held on an ongoing basis, but we're talking about potentially terabytes of data after just a couple weeks. So there's not a large period of time that that data is required to be preserved unless a trigger is put forward by the planner and operator to initiate that.

So we want to get into how these things interrelate as part of this quick presentation, and I see this as part of like the three-legged stool that happens with real-time assessments. You've got data requirements, data-sharing requirements, and then the analysis requirements. The difference here is that we're initiating all three versions of this three-legged stool simultaneously. So this has been a lessons learned for how we do joint standard project development, three different projects working somewhat in tandem. Not everything was done completely. We got some lessons learned, I'll say, and some improvements that we'll make for the modeling aspects as well because there's three projects that will go through a similar type of need to coordinate and collaborate on a single solution.

So PRC-028 looks at making sure that the installation of the equipment is done. We'll get into the implementation questions and discussions tomorrow, so I won't go into the Phase 10 implementation through 2030, other than to say, for all of 901 -- that's Milestones 2, 3, and 4 -- all have to be fully implemented by 2030. It seems like a long time, but it's not. As we all know, just a standards development project is taking a year or two, acquiring vendors, getting through supply chain issues, making sure you've got contractors onsite for testing and validation. It's going to take a lot of work, and don't start two years from now or three years from now. It's really critical that we start soon and understand the issue soon so we make sure that things are in the works and scheduled and being able to be coordinated with reliability -- or with the regional entities as well.

Next slide.

For PRC-030 -- did we skip PRC -- did we skip a slide? Thank you. Yes.

So Project 2020-02, PRC-024, we're looking at frequency and voltage Ride-through requirements. It's why we're all here today. We're looking at establishing capability-based Ride-through criteria and performance-based Ride-through criteria. So the difference there being the design piece where you have -- whether or not you've communicated what the unit is capable of doing versus how it's actually performing in practice. During a voltage or frequency excursion, what is it actually doing? Does it match? And so we need both of those things in order to be able to align them and make sure that they're the same. There's going to be differences based off of things that are as-built versus as-designed, but we've got to be able to make sure that we're moving forward with comprehensive solutions. That means we need both of these, and that's what PRC-029 does for IBR.

PRC-024 was modified slightly. It takes Type 1/Type 2 wind. It takes synchronous condensers and synchronous generation. So we're retaining PRC-024 with those changes to ensure that those assets are covered. So PRC-029 really focuses on those asynchronous, you know, Type 3/Type 4 wind and PV where we're looking at IBR that need to be looked at a little bit differently.

Next slide, please.

PRC-030, similar conversation here where there was an IBR version of the standard created, looking at assuring that analysis is being performed. Who was the responsible entities, what were the trigger criteria, and how these things interrelate is that PRC-030 really triggers what is required to be evaluated. So within PRC-028, we talked about how there was disturbance monitoring data that had to be captured, that information needed to be triggered for. We're going to call -- we're going to investigate this particular instance. It's not going to be on the generator owner to know when a disturbance occurs. They're not looking at the wider area view. They may know because of their own operations that might trigger it, but it's going to be on planners and operators, primarily operators, to be able to determine whether or not excursions occurred that requires additional analysis to be able to identify if generators either failed to meet Ride-through or they were able to Ride-through with adequate bandwidth.

So PRC-030 is really what ties PRC-028 and 29 together. Again, that's that three-legged stool that are all really needed in order to be that single solution.

Next slide.

So finally, this is just a graphical representation of what I just went through. There's a voltage or frequency excursion that happens on the right and it -- for one, it's looking at the criteria individual generators will be able to tell if they rode through or not. And if that individual analysis doesn't occur because the generator owners didn't know that there was an excursion that occurred, then PRC-030 that's over there on the right-most block would be the one that triggers that additional analysis to ensure that it's performed.

The data-sharing aspect comes from PRC-028, so that left-most block. It's really going to be the thing that's going to be relied on to perform those analytics, but we got two other boxes down there that are critical, which is Milestone 3 and Milestone 4 are going to require this information. So having that data-sharing capability, the ability to trigger sharing that data is essential for validating models, making sure, again, as performance is being incorporated more into these standards, that we have performance evaluations during model validations and not maybe just five-year stage testing based off of what -- or the unit can do and based on the facts and circumstances at the time that unit is tested.

So model validation performance may happen on an ongoing basis, may be triggered on some other aspect of, you know, the operators or planners' criteria or working groups' processes. That's going to be developed within the modeling teams that are focused on Milestone 3, but we won't go into that today because that's obviously a whole other scope of work and we've got a whole year to do it, so we'll put that one to rest. Milestone 4 is taking everything that's captured in terms of the performance data and the models, and then conducting planning and operational studies after that.

So next slide.

At this point, we'll open it up for any questions. I don't know if there's going to be questions. If we can move to the Slido slide as well. Well, while that's getting ready just to go through how we're going to be doing the Q&A, within the room, we've got two microphones set up, which are between the two hallway the two columns here. If f folks have a question to ask in the room during any of the presentations or panels, please line up behind the microphones. We'll alternate between questions in the room and online. So the online Slido is going to be available during presentations. We're going to have the -- those questions locked so there won't be any questions that will be able to be asked at any other time. We're going to close that down and reopen it every time we have a -- the possibility to go to a Q&A.

We do have a code and instructions here coming up. There we go. Thank you.

So this is going to be the same information that will show multiple times throughout today and tomorrow. You're able to use the QR code if you want to scan on your phone. You are also able to just go to Slido.com. There will be a space to put in an event code. We're using "Ride-through" because why not? So capital

"R/hyphen/through." There's no password. You should just be able to get in. We will have moderated -- a moderator looking at the questions to make sure things are on topic, that it's appropriate to the panel that's being presented at that time. So this slide will be shown multiple times, so if you miss this information now, you want to grab a screenshot, please do, but that will be how we go through the Slido Q&A.

So if there's any questions online -- not sure if there's any questions online right now. Okay. Excellent. All right. I think we could probably go to the next presentation then, which will be a 15-minute break.

(Laughter.)

MS. CALDERON: Oh yes, yes. Question in the room?

MR. MAJUMDER: Thank you so much, everyone.

MS. CALDERON: Oh, just for anyone asking a question, could you please provide your name and who you're with, if you're in the room?

MR. MAJUMDER: Absolutely. My name is Rajat Majumder. I work for in Invenergy, which is a renewable energy developer here in the U.S., and I'm also on the Standard Drafting Team of PRC-029. So great presentation, good setup of the meeting.

I heard a statement from Rob that -- he made it very firmly that the risk is sufficient, technology is sufficient, so let's get it done, it's not a matter of easy and hard. Absolutely agree with that, but that risk sufficient part should be data driven. Yes, technology is sufficient. Of course there are -- there is gap between what technology can offer now, and that's why we are here today. Otherwise, we would already be having an approval on the standard. What is missing until -- is how the sufficiency of the risk is being established for what technology is shot. So that's what my humble request to the entire team, that as we go through next two days, let's keep that in mind, that whenever we are trying to establish a risk, let's find out what is needed for the reliability of our bulk electric system that we own. Thank you.

MS. CALDERON: Okay. Still no questions on online? All right. We'll go ahead and --

MS. CASUSCELLI: All right, Jamie. It looks like we do have a couple of questions online.

MS. CALDERON: Okay.

MS. CASUSCELLI: So first, "does the spoken word during this Technical Conference become part of the NERC/FERC record or only the comments provided in writing?

MS. CALDERON: Oh, yes. So we are recording this webinar or this conference. It will be posted. The transcript as we'll be able to have for our record of developments. Everything here for this conference is a little bit atypical because we're using it as part of the -- our response to invoking Rule 321, so this is going to be part of our full record of development. The questions that are online that are asked, we'll preserve those. We'll be able to add those to the archive of questions, questions in the room. We do have a court reporter in the room, and that's why -- one of the reasons we're asking folks to be able to provide your name and who you're with prior to asking questions so we'll be able to ensure that everything is -- everything's captured.

MS. CASUSCELLI: All right, a couple more. David McNeill from Certrec is wondering, "Does NERC anticipate the replacement of synchronous generation with IBR-based generation to lessen the severity of frequency events?" We'll probably get through that.

MS. CALDERON: Less than the?

MS. CASUSCELLI: Less than the severity of frequency events.

MS. CALDERON: Not sure I understand that question.

MS. CASUSCELLI: It says, "Does NERC anticipate the replacement of synchronous generation with IBR-based generation to lessen the severity of frequency events?"

MR. SHATTUCK: Yeah. I mean, I'd say probably not. I mean, the thing we can certainly say is that as we transition towards more IBR and higher penetration, things are going to change. If we do nothing, right, and it's all grid following inverters, and, you know, all the synchronous machines are gone, then things are going to happen that we don't expect. They will probably be worse than what we've seen. Now, if we do this in a thoughtful way and replace those synchronous machines with machines that are, you know, tuned right, with the right parameters or the right capabilities like we're going to talk about today, then we could be relatively certain, you know, if we go forward, that even if the events change their nature, that we're capturing that with our, you know, study work, right? If we do better studies and study what's actually going to happen and study what will come next, then whatever happens as far as the changes that happen, we'll be able to mitigate those as much as we can.

MS. CASUSCELLI: All right. Thanks, Alex. I have more. What is the code for Slido?

MS. CALDERON: There is -- so the event code is "Ride-through," capital R and then a hyphen. There's no password on top of that. So you're able to enter in additional information as optional, such as your name, so that we're able to respond to that question in chat, but the event code is "Ride-through."

MS. CASUSCELLI: And are the preconference comments going to be posted?

MS. CALDERON: Okay. The preconference comments that were provided as part of the larger set of comments that we requested from industry, we do not intend to publicly post those. We are collecting those as a matter of our, again, record of development. If we as part of our filing have additional follow-up questions, we might reach out to those individual comment submitters for additional information. If it's additional information that's requested by FERC during our filing, we're going to provide that as well, but we have no intention to post the full comments.

MS. CASUSCELLI: All right. Okay. There's more questions. We're getting more into, like, the technical stuff if you want to approach this now or --

MS. CALDERON: Yeah, if it's starts getting into the actual frequency or voltage criteria, we'll want to wait for that panel to go because we'll have an OEM panel today and another panel as well.

MS. CASUSCELLI: Okay.

MS. CALDERON: So as long as it's questions related to kind of the larger Milestone 2 work. Some of this, like, larger conference work stuff is fine as well since this is --

MS. CASUSCELLI: Okay. Okay. So we'll just hold a lot of these questions until the end, I think, or later.

MS. CALDERON: All right. Well, we'll put a pause now. We'll go ahead to a 15-minute break, and food, I think, is still probably down the way, coffee and water outside, and we'll see you in a bit.

(Break.)

MR. BENNETT: Okay. So it looks like we're getting started here. Again, I'd just like to say thank you for all the participants so far. Great technical presentation by Jamie to kind of set up this discussion. And then as far as right now, I believe that we have -- I believe that we are entering into our first presentation which is review --

(Technical difficulties.)

UNIDENTIFIED SPEAKER: Lithium batteries.

MR. BENNETT: Okay. This microphone works now. So we're going to enter into our presentation to review the voltage and frequency Ride-through criteria in the PRC-029 standard. So helping us with that are our speakers today, which are our Drafting Team members, but Husam Al-Hadidi and Shawn Wang. So I'll hand it over to you, and thank you for your presentation today.

MR. WANG: Thank you. Thank you, everyone. Good morning. My name is Shawn Wang from Enel. I'm the chair of the Standard Drafting Team. Yeah, I'm happy to present the -- some background of this standard development over the past, like, two years.

Yeah, maybe next slide, please.

Yeah. This slide shows the Drafting Team roster. I really appreciate all the membership, yeah, during the past two years. It's really hard work for the Drafting Team. Yeah, I think everyone actually here today just on behalf of us. Yeah. Actually, some of the membership, yeah, in this room -- in this room, yeah.

So yeah, with that, actually, next slide, please.

As Jamie, mentioned, the -- she just put the time machine back to 2023, but I will get back even further of this Drafting Team back to 2020 because the project named 2022 -- 2002. Back at that time, actually, there's a SAR from NERC to revise the standard -- existing standard PRC-024 to include the dynamic devices into PRC-02024. That project start from 2020. That's the reason why actually this project just grandfather that project to move forward to include -- associated with this standard.

Yeah. Next slide, please. Yeah.

Actually, in 2022, actually, NERC issued another SAR to revise the PRC-0-24-03, actually revise the generator Ride-through standard. The background for this SAR is like from the system events, right, several system events. Actually, after the analysis, actually, we -- the NERC team identified there some missed operations. Actually, the widespread generation loss actually reduced the output, right, from the IBRs from the wind, solar, or even the BES. Actually, the from -- the system event analysis identified there's some reliability risks, yeah, from those abnormal trippings from the IBR resources.

From the analysis, actually, the -- one of the issues is identified that the existing PRC-023 -- PRC-024-3, is just equipment protection setting standard. It's not sufficient to cover the IBR units. In that SAR, it's proposed to address those reliability risks to propose a more suitable performance-based reliability standard.

Next slide, please.

Yeah. The Standard Drafting Team start from actually combined those two SARs and start working on this standard -- the standard to work on this project. Actually, the project start from 2022, I think -- yeah, 2023. At that time, actually, after the extensive discussion, I think as mentioned by David and Rob, actually, the Standard Drafting Team realized that there's difference between the synchronous generator or the traditional generator and the IBR units. So approach-wise, actually the Standard Drafting Team decided to revise or modify the PRC-024-3 to retain the reliability standard as the protection-based standard, only applicable to the single generator and the synchronic condenser Type 1 and Type 1 wind turbines, and to create a new reliability-based standard, the PRC-024 -- PRC-029, address the inverter-based resources to Ride-through these system -- voltage and the frequency excursions.

Actually, at the time of the last year, actually, the FERC Order 901 came out. Actually, the Standard Drafting Team decided to coincide with the Ride-through standard proposed by the attribute standard -- no, sorry -- the need to understand and follow the FERC Order 901.

Yeah. Next slide. Previous one. Go back one slide. Yeah.

This slide shows the timeline, actually, for the Standard Drafting Team actually after the -- during the -- more than -- this year, right, after the 901 released. Actually, the Standard Drafting Team work very hard after that to meet the timeline, right? Actually, it's very time constrained. Actually, the first draft released in March of this year, and the first comment period run through March 27 to April 27. Actually, the first draft didn't pass the ballot, and they received almost 200 page comments from the stakeholders. The Draft Team were, again, working very hard, went through a series of meetings, including one in-person meeting in Cleveland in May, to address all the comments and release the second draft the -- of the standard.

So the second drafting -- the second comment period ran through June 18th to July 8th of this year.

Again, actually the -- it didn't pass the -- after received the comments, actually, the Drafting Team set up several meetings and address those comments, actually make revisions to the draft, actually, within very short time duration from July 22nd to August 12th. Then they create the -- make the third draft, but unfortunately, still didn't pass through the ballot. Then on August 15th, the NERC Board of Trustee invoke this Rule 321, so this technical meeting, yeah, yeah, came up. Yeah. So the -- just one thing I want to mention. The PRC-024, the revised PRC-024 passed the ballot, so we just focus on the PRC-029 now.

So next slide, please. Yeah.

So with that, actually, I will pass the microphone to Husam to describe the current or latest redline of the Draft 3.

MR. AL-HADIDI: Good morning. Husam Al-Hadidi from Manitoba Hydro. I'll just -- I'll go through the steps where we were as part of developing this standard with this Draft Number 3. Just I'll go in the progress how we came to this stage from standard from Draft Number 1 to Draft Number 3.

First of all, we were having challenging of the IBR definition, which was not there, and it gave us some way -- went through different phases of it, but until it was now approved by NERC, and it was passed the ballot. That's why it's now included in the -- in the standard itself. Also, there was some struggle with the transmission owner. Is it going to be part of applicability or not? And the reason for that is because we -- part of IBR, which is the offshore or any IBRs connected through the water source converter, which was sometime it could be owned by the transmission owner, but after a good discussion and looking at some example here in U.S., we found there is not a case exists, so -- and it was adding some confusion to the stakeholders. So we removed the transmission owner from the applicability part of it, and it's only now applicable for generator owner.

Next slide, please.

We started first with Draft Number 1, which was six requirement, but we ended up with four requirement in Standard Number 3, and I'll speak about why we have moved some of this requirement or remove it from Draft

Number 1. And the first requirement was about the voltage Ride-through, and in the first draft, we were having only -- it wasn't -- it was only event-based analysis. It was not a capability-based standard, but we understood that analysis part, it requires some measurement, and that measurement, it may not be available at the early stage of the implementation of the standard. And we thought it's the right way to go, is just to make sure that the capabilities already exist. And then event-based analysis will -- can confirm that if that's -- if it was how it was designed and it was -- performed as expected.

So we included the designing -- the design and operate, and it was -- that wasn't integrated in Draft Number 2, moved away from Draft Number 1, which was only about just operate the IBR, and R1, it just focus on the Ride-through the voltage. And we had two table for this Ride-through, and the two -- the table is one for the wind IBR and other -- and then -- and the second one for other IBR technology. And the reason for that, we want to have as wide as possible voltage Ride-through criteria with understanding that the system short-circuit level and they (inaudible) significantly change. And even the load itself -- IBR load will integrate it a lot on the system, and that the need of Ride-through -- of a larger voltage Ride-through, it'll be expected for ability to mitigate any future risk. For that reason, we were -- we went to the two tables and with understanding some limitation could still exist for the wind technology.

And here we have the -- we list some of the exemption from the voltage Ride-through where it could trip for a reason as listed in this fourth bullet. One of them is for (inaudible) protection, and second, we understood there's an exemption, and that exemption may give you a different criteria than what's there in the table. For example, like the 0.9 per voltage. It may -- you may not be able to go for three second. You may be able to go two second for legacy equipment only or legacy IBR. So that's the reason it's one of the exemption there.

And also Bullet Number 3, it used to be as a separate requirement in the standard in the first draft, which is the -- which is the positive sequence instantaneous voltage jump. But we said it was -- we thought it may -- it make it more fit to have it as an exemption because really only if unit trip, then if your voltage was -- if your base angle jump more than 25 degrees, then you could use it as exemption from the compliance part, and you don't have to worry about it as part of -- if you don't -- if you don't have a protection, if you don't have this trip there, so you don't have to be worried about the compliance and how to present it as a requirement.

And also, there was some question about the voltage per hertz, and we said maybe it's good to have some criteria to ensure just in the design because we added the capability and there was a compliance question how to prove that the design can work at the boundaries of the voltage and the frequency at the same time. That's why we included the voltage per hertz exemption criteria here.

Next slide, please.

This is the measurement. Actually, the measurement were changed somehow to reflect the -- some feedback we got from multiple stakeholder, and I believe to the stage where now it add more clarity. If you have any question, we can answer it at the end of the -- at the end of presentation. But for now, next slide, please.

For R2, I said R1 was still a voltage, but Ride-through R2, it went now to focus on the -- focus on the performance of the voltage. And here we split -- based on the table, there is three operating region, which is the continuous, mandatory, and permissive region. And for each region, we presented the performance criteria needed after a disturbance. However, we understood there is a weakness for every system, and you cannot come with some criteria which can fit all.

We try to come with as much as possible adding flexibility to the requirement, at the same time giving some guideline for a starting point whenever is needed. So we started with a lot of performance requirements as included and very specified, like it is going to be different how much your reactive power for every voltage there. What's the relationship between the power and reactive power?

However, but we understood that could be challenging for some region, and it will not fit -- we cannot come with answer fit all systems. For that reason, we remove some of this language from the standard, and we ended up with some language still there, which is meet the minimum requirement in our -- in the Standard Drafting Team opinion, but at the same time, having some added flexibility still there for the TB and for reliability coordinator and planning coordinator to come with their own criteria if it's -- if it's going to be different than this, to mitigate whatever reliability issue they have in their system.

Next slide, please.

For 2.2, this focus on mandatory operation region, where 2.1, it was the continuous within mandatory, and this one is merely saying that we understood there's a reactive -- there is real and reactive power. And we said that's always going to be the fault, is reactive power, it makes sense if you are having a voltage issue, you need to support the voltage system. However, we understood for system -- for other system, it could be real power priority is the need because they may have some frequency issue, and they need to mitigate it or deal with it.

So we come -- we wrote it in such a way where there is a flexibility there, but preference or the fault is already provided.

Next slide, please.

For 2.3, it is actually focused in the -- in the reaction of -- this one in permissive region where it's -- here, it's looking at part of the -- part of the FERC order was that you couldn't use voltage cessation or the blocking of the current. However, we understood that below 0.1, especially positive sequence voltage, if you have your three voltage phases already all below point-zero or close to zero, then it's very hard for the IBR to still continue to produce any power or try to contribute to the system.

So for that reason, we said, instead of allowing them to trip, we said, no, don't trip because really, it may, it may not able to provide any support after the fault recovery. So we say you could block if your booster sequence voltage below .1, but at the same time, if you booster sequence goes above .1 within five cycle, you have to reconnect to the system, and you have to start -- continue exchanging current, and you have to meet the requirement as stated in the 2.1 or 2.22.

For 2.4, it's focused on the -- on the response of the IBR after clearing the fault. It was a concern stated that sometime the -- based on the surface level or the -- or the gain, or the right -- or the recovery time, it may become a little bit -- or even the mode of operation is reactive power, how much reactive power was exchanged, it may cause a high-voltage response after clearing the fault, and that voltage may go outside of no trip zone, and that may cause itself to trip. So we see that it need to be designed or have the capability, and it has to be shown that it has -- it could be tuned to be able to maintain the response within no trip zone -- voltage no zone.

Next slide, please.

For the 2.5, this is for the recovery from the event itself. And for the recovery, as I said, the flexibility is added there. We said it needs to recover, and that was part of the FERC order, within one second. At the same time, it has to recover fully for the pre-disturbance megawatt, and -- but we understood that it may not be able to go to the full megawatt because of some water or some change in the -- in the -- in the -- in the capability of the IBR is not for tripping an individual IBR unit. It's only -- if it can -- even if we trip some IBR unit, but it can maintain its power after the disturbance, we say this should be a compliance. It shouldn't be -- have an issue with that, but we understand in some cases you may not able to cover for 100 percent, and we give them a flexibility, which is going to be provided by their associated transmission planner or operator or coordinator.

Next slide, please.

This is the fun part, which is R3, which is the frequency Ride-through. We had to struggle with this one, I must say. We understood the system is going to change in the -- right now, the system is going through significant change, and the IBR technology is going to be -- penetration will be increased significantly in the system. And people have not enough experience or exposed to the system to the high-frequency event or low-frequency event. So we try to write something which, in our mind, how it's going -- the system going to behave within the coming four, five, six, 10 years, and what's the availability needs for the system.

So FERC stated that you cannot have any exemption criteria. So we will -- we tried to write something which we try to have some frequency requirement there, performance requirement Ride-through, but at the same time with understanding some legacy equipment may not be able to meet some of these requirements. So we wrote it in such a way where we did not have any performance, only Ride-through, so we are not -- there is no primary frequency controller as part of this requirement. You need only Ride-through, and you need to keep connecting and exchanging current, but you don't need to respond to the frequency event as it is because there is no required frequency performance.

And the challenge was for the ROCOF, which is 5 hertz per second, but we understood it's -- this value cannot -- it's very difficult to calculate during the fault. So we make it very clear that this is not during the fault event. It should be after the fault and should be for really actual load and generation and balance event.

So and and we come with -- we widened the table beyond even the IEEE 2008 and Ride-through, understanding that the nature of the system will reduce a lot, and we -- and the technology are much capable of Ride-through of frequency envelope. So and maybe today we'll hear from some -- OAM about their experience with that. But we widen this range of frequency larger than for the first -- six second larger than IEEE just to make sure that it's -- the future system will be able to have that advantage of maintaining the IBR for longer or larger exertion of frequency.

At the same time, also, the load will change significantly. IBR load will be there, and that will make rate of change, interruption of power will be significant, and the rate of change will be significantly, even most likely, more than 5 hertz per second.

Next slide, please.

The R4, it's -- is the exemption. In this one, we moved in different stages in our -- in our Drafting

Team to come to this language where it's in the -- in Draft Number 3. What we have here, we came -- we agreed that an exemption, this is like a temporary requirement because this one only valid for the first year of -- after the -- after the effective days of the standard. So after that, you have one year to apply for exemption for only voltage, which just mean that for R1 and R2. And for this, too, requirement, you could, if -- for legacy equipment, you could do exemption. We list some of the information need to be provided in your submission request for exemption. We understood there is a risk and some assessment need to be there, but -- that could not be explicitly provided in this requirement. But we said it's based on -- the exemption will be guaranteed not based on the risk. It just based on meeting this requirement itself.

Next slide, please.

Here, we also provided the mechanism and to whom this exemption needs to be submitted. At the same time, we said that how you need to deal with it in the future, if you are -- if your exemption has been -- you replace some of the equipment and if there is any request, additional information from transmission planner or transmission operators or RC for additional information. It could be modeling, it could be other information which may help them to assist the risk and to model or to try to include this as part of their study to understand their limitation within the equipment.

Next slide, please.

I think here, just the tables of the voltage and the frequency, so we have modified them, and there's not much here.

Next slide.

The same thing. This is the frequency, as I said. For the first six second, we have increase the level up to 64 hertz in the overfrequency part and to 60 56 hertz in the under frequency for six second. Beyond that, we try to match some of the existing IBR standards within the footprint of U.S.

Next slide. Thank you.

MR. WANG: Yeah. One more thing I want to mention is, like, for the -- at the first draft, right? We also include the transformer voltage, the requirement, along with the attribute and 800 standard. But during the Drafting Team, the development and also the participate of the attribute Standard Team, right? We realized that it's very complex issue at this point, and we just remove the -- remove that requirement and just put the one atom in the attachment of the Table 1, yeah, such that actually, we just try to avoid the instantaneous overvoltage tripping, yeah. That's not allowed, yeah. Just one point we just mention, yeah. Thank you.

MR. MAJUMDER: Thank you, Shawn and Husam. Rajat Majumder from Invenergy. I'll go straight to R3, of course. So two primary comments that I would like for the entire room to consider and provide some guidance. One is based on FERC Order 901. Is it true that the FERC Order 901 does not allow weaver to frequency, Ride-through, or 901 is silent on that. It does provide explicit weaver to voltage, right? So I understand that, but I just wanted to touch on that.

The second one, which going back to my comment earlier this morning, the sufficiency assessment of the risk should be data driven. And if we look at some of the earlier even that has happened, I fully agree that there has been, even on where large amount of IBR tripped off. Majority of them, if we review the NERC alert carefully were due to wrong settings. So if we try to solve a problem of some equipment settings being wrong with a very broad stroke of making the requirement much more stringent, I do not know if that's the right way of doing things.

If we look at, again, on the data that's available based on the Texas Uri event, the FERC report showed the frequency nadir was 59.4 hertz with 50-percent generation trip, then followed by 25-percent load setting. I was in Sigrid, Paris last week. There was a four-hours long session or large disturbance all over the world from both 60 hertz and 50 hertz, and many of them has significantly more IBR penetration in their system compared to here in the United States. I haven't seen any one of them, in 50 hertz, the frequency ever went down below 49.4.

So all I'm trying to say that asking for a frequency right requirement thinking it may happen in the future appear, to me, be pure speculation. So I would like the entire room to consider those fact and, again, humbly request to establish the risk sufficiency assessment based on data that's available to us. Thank you.

MS. CALDERON: All right. Jamie Calderon with NERC. Just in response to the question, the team was advised with Legal there was no exemptions that were allowed for frequency within FERC Order 901, so that was routinely provided to the Drafting Team through consult. FERC Order 901 doesn't even speak to any types of frequency exemptions. And we're going to get more into that conversation in this afternoon's panel and, of course, with the panel tomorrow morning. So we'll get into more details for that.

But also, just as a reminder, we do want to keep the Q&A to questions to either the presenters or the panelists. So please, please try to keep to that so we can ensure that we're allowing time for other people to ask questions.

MR. GOGGIN: Thanks. Michael Goggin with Grid Strategies. A question about the frequency Ride-through curves in PRC-029. Can you talk a little bit more about the source of those curves and the technical justification for the relatively wide frequency bands in there?

MR. AL-HADIDI: The idea behind that, we looked at -- I come from Manitoba Hydro. Our system, really, the inertia can go very low, and we have multiple event where we -- our frequency -- we have rate of change of almost 8 hertz per second based on our inertia when we -- when we, our tie line is broke from the system. So we understand the event can be very severely, and with low inertia, you need -- you need to Ride-through larger, wider range of band of frequency.

And we under -- also the base on this limitation we have right now in BRC 24, it was based on the actual physical limitation on thermal turbine, which is not the case in many cases for -- other than IBR, the Type 3, where it have some -- it's still in the integrated system. The other one is already buffered by the inverter itself. So we -- the thought was the opportunity is there. The need of the system will -- the inertia will go lower. Even the short sector will be going lower, and that's mean the rate itself can widely spread as a voltage dip where it can impact significant number of load and the load IBR base load. And this all can create a significant movement of the frequency.

In addition to that, also, we also understand that the IEEE say that 5 hertz per second. If you look about it, so it'll then take more than one second or less even to go beyond the 65 hertz or even to go 55 hertz if you are close to this 5-hertz-per-second rate of change. So it doesn't give a time -- enough time for the IBR to respond for a frequency event. So we said if the technology allowed that, why not to bring it, and the idea that it's not a protection base, it don't even -- in my opinion, the frequency or your protection setting should be based on actual capability and not based on the boundary itself as specified here.

So in many cases where we have our equipment, the Ride-through frequency in in many area, like Manitoba Hydro have, we have up to 82 hertz. It has to Ride-through. So this number, in my opinion, was insignificant based on the system need and the system need maybe there in the future. Thanks.

MR. PATEL: All right. All right. It's working. So you know, everyone is going to talk about frequency Ride-through and exemption for legacy. I'm not going to talk about it just now. But by the way, Manish Patel, EPRI. Whatever I say or ask are my own opinions and questions. Please don't sue me. I still have two young daughters to send to college.

(Laughter.)

MR. PATEL: So a couple of general comments. Look, I'm supportive of the standard, but the standard remains completely silent on when IBR is required to Ride-through, for what system conditions. The IBR may be designed today, installed today, commissioned today to Ride-through for a given system condition. Ten years go by, the transmission system has changed upside down. Is IBR still required to Ride-through? I think -- I think it's a -- it's a -- it's a gap that the standard completely remains silent and simply states Ride-through no matter what the transmission system condition is, what the neighbors are doing, and all that kind of stuff, right?

The second thing is the way the standard is written right now, if the differential protection on a generator step of transformer mis-operates, then the IBR is out of compliance because it tripped when it shouldn't have tripped. I do not recall exact details, but in 2022, there were 1,200 mis-operations on the bulk electric system, and it's just life happens, right? So there has to be some exemption for things that are beyond control, right, water dripping from the roof in a control house, mouse in a control house chewing up cables, things like that. We talk a lot about what IBR is expected to do in a continuous operation region of the voltage. I think that is probably unnecessary requirement because the whole purpose of the standard is Ride-through when the voltage and frequency are normal. Half of the page of the standard is actually asking for IBR performance when the voltage is almost normal, right, so things like that.

I had something else in my mind, but it's slipping. I have opportunity today and tomorrow then.

MR. AL-HADIDI: Thank you for the questions. Manish, we discussed some of this one before. So maybe in the first part, which is about the system strength, where it was -- where it was designed, the idea were -- the team were, the Drafting Team, that we did not touch the stability part of the IBR. So we said we are -- in the standard itself, we did not speak about the, what you call the rising time or starting time, or is going -- is it going to be stable or not stable. So we understood this can impact the stability, and there's the third phase, which is the Milestone Number 3, which is, you know, about the operation, and that need to be caught at that stage of the analysis, and I believe that will be -- could be advised to revise some of these parameters or re-look at it as part of that -- part of investigation.

But if it -- if that part provide now recommendation for change of that to maintain for whatever short-circuit level system become because you cannot say that I design today, system have changed, now for reliability, I don't have to do anything about a system change. System event happened, everyone cannot Ride-through, and the system can collapse or reliability issue. So I think that need to be addressed as part of the how the phase three or my phase three of the standard need to look at it, and in that case, we looked at it where it need to be looked at, the stability of the IBR.

For the second part, I believe your second question, if I remember was about --

MR. PATEL: Mis-operation of protection.

MR. AL-HADIDI: Mis-operation, yes.

MR. PATEL: Just real-life things.

MR. AL-HADIDI: Yes, I fully agree. Where the standard -- we work with the BRC/TRT. As Jamie stated, that these three standard really are -- they were integrated with each other to some level, what our -- the Standard Drafting Team at least thought. Maybe it wasn't clear. We'll see how the thing goes. We thought that the BRC 29 provide the criteria itself. However, the assessment itself is done by BRC/TRT because there's even the correction plan. Everything is coming -- going there.

In the PRC-030, it was very clear stated that if it was for mis-operation, you don't need to investigate it, and is no -- no corrective action is needed. So it was already exempt by the IBR tripping for -- mis-operation protection was already included, in our opinion, at least in the PRC-030, which maybe this a good point for discussion, if that was really the right way to do it or not, but that's where we are.

MR. PATEL: Yeah. So I understand that. The standard has to stand on its own, right?

MR. AL-HADIDI: Yeah.

MR. PATEL: PRC-030 only talks about the operation of BES under PRC-004. You can have a collector feeder breaker trip because of, you know, real-world issue, and that's not a BES element. If it's not, then it's not part of PRC-030, but PRC-030 criteria is met and PRC-029 criteria are met, right? So I think -- anyhow, there has to be some indication of things in the standard. Right now, the way it is written, voltage was in the mandatory operation region, frequency was in the, you know, mandatory operation region plan disappeared, and there that has -- it's out of compliance. Anyway, we, we can talk --

MR. AL-HADIDI: Yeah, yeah, that's a good point. That's a good point.

MR. PATEL: Yeah. The last point that I just recall is this whole concept of performance-based standard. I think when the whole idea of performance-based came along, it was not the fact that perform under 24/7, 365, next 25 years, in that manner. It was more about voltage and frequency trip setting. PRC-024 is not working. We need to go for performance-based. Performance-based was -- continue to work when the voltage and frequency are within given bends, right?

MR. AL-HADIDI: Yeah.

MR. PATEL: So this whole concept of performance-based is a little bit misaligned than the original thought five years ago when it came out of IRPTF at the time.

MR. AL-HADIDI: No, I agree. Thank you.

MR. MAJUMDER: Rajat Majumder. So Husam, when you responded to the other gentleman question, I have heard many will, and you referred to Manitoba system. Now, I'm sure that you might have seen an ROCOF of eight hertz per second. That's shocking, but we cannot take the requirement from a very specific region and generalize it, right? Again, referring back to my

SIGRA session, there was a gentleman from South Australia. He presented a lot of experience with a peak load of 3 gigawatt. Now, are we going to take a South Australian event with a peak load of 3 gigawatt and apply that to Eastern Interconnect with 950 gigawatt? So when we are creating a reliability standard, we need to be aware of the context of it. Cherry picking and then applying blindly is not the right way to do.

Second of all, you mentioned that, well if the design can do it, why not? It's not about just the IBR. We'll have transformer which are not under PRC-029, and I don't want to speak for them because we have enough expertise today within the room. I'm looking forward to the manufacturing panel this afternoon. We have representative from FOSDA, Siemen Gamesa, Hitachi Energy. They are the top at their field. Please hear from them. If you are going to have transformer operating in such a low frequency ban, there are going to be many other issues, unintended consequence. It's going to make the transformer for no apparent reason. That's not the right thing to do, but transformer is not covered within our PRC-029.

MR. AL-HADIDI: (Inaudible) versus (inaudible) hertz was addressed by R1, but as I said, let's maybe -- let us leave it -- this topic for further discussion within the industrial, what do you think about the frequency range and if the capability's there or not, and what's was really the concern. But we did not get too many comment from the stakeholder about the range of the frequency. Most of their concern was with the ROCOF and the legacy equipment where it may not able to ROCOF value.

MR. MAJUMDER: Yeah.

MR. PATTABIRAMAN: Hi. Dinish Pattabiraman from TMEIC, you know, equipment manufacturer. So I have a question broadly on the standard in terms of why the deviations in the standard compared to IEEE 2800 language, which has been widely accepted in the industry with the high balloting rate. And there's also about to be a test procedures, IEEE 2800.2 that's going to come for the standard. Why deviate from the language of IEEE 2800, which is widely accepted in PRC-029?

MR. AL-HADIDI: We did not -- our intent was not to diverge or to follow IEEE 2800. We started there, but there was a lot of requirement there, and some of it actually to be hard to write it, or maybe to moderate, or make it as part of the compliance itself. So based on that, we looked at the variety of the need for the system and from reliability perspective, that was the intent. And wherever we found the reason to divert from it, we did. And it was also, as you know, it was FERC order, was also constrained in the way we looked at some of the requirements.

MR. PATTABIRAMAN: So but in terms of compliance, you know, 2800.2 also offers a variety of test procedures. I'm not sure if there's going to be a test procedure that comes for PRC-029, but the strength of 2800 is that it offers these kind of test procedures which different people can study and comply -- and at least study compliance with, whereas deviating from 2800 language -- for example, there is a language for phase jump that says that, you know, 25 degrees but initiated by a non-fault, you know, that kind of language was not there in 2800. There are small changes like this throughout the standard, including the frequency Ride-through requirements. So I'm just curious on what the thoughts of the Standard Drafting Committee are on that.

MR. AL-HADIDI: As I stated that, yes, there is some slightly different, but I'm also part of the -- of IEEE standard, and it's not -- it's not the perfect standard. And all it mean that there is always need to change, and there was opportunity for us to look at from a bit perspective like the frequency, why it's there. And when we asked the question even why this value was selected was not enough, always a good answer from people who were involved in IEEE standard at that stage.

So it's based on the -- your experience, and this is the task of the dd task of the Drafting Team to come and consulted with the industrial and the feedback we got, and based on that, we moved in this direction. Thank you.

MR. PATTABIRAMAN: Thank you.

MR. WANG: Yeah. For this one, I think two parts I address. Yeah. For the 29th standard, right? I believe most of the -- especially for the voltage part, pretty much align with the IEEE 2800 standard, yeah. I think for frequency part, yes, actually there's some division, right? So for this issue, I think even for this -- even within the Standard Draft Team, that's the ideal -- the approach we adopt so far.

For this Technical Conference, one of the main purpose for that -- for this conference is, like, we discuss the frequency part, right? I think for that part, actually, we have that dedicated topic to discuss that one, yeah. If the OEM even for the for BES or even for wind manufacturer, right, if has any not issue or concerns with that -- with that standard or the requirement, yes, we -- the Standard Drafting Team really want to hear the voice, yeah. That's the one -- the main for this one.

For the second one, for the -- for the testing procedure, right? I know the IEEE standard, the 2800.2 is working on that testing procedure. I think it is still ongoing efforts, right? The Standard Drafting Team has very closely participate that -- the working groups. Actually, we just adopt that approach maybe in the future for the -- for NERC standard, right, for 29 or even the future, the revisions, yeah, for sure we can adopt that approach in the future. But at this point, I think even for the IEEE 2800.2 is still ongoing efforts, yeah. So that -- I think I just want to bring the attention to the team, yeah.

MS. CASUSCELLI: So we've got a number of questions online. I'm just going to interject here. Could you share the evidence or data that NERC has indicating that the bulk power system might experience frequencies up to plus or minus 4 hertz per six seconds?

MR. AL-HADIDI: Even we don't -- we cannot present information for even the current -- whatever their IEEE standard, which is the 57 hertz. So the evidence, you don't have an event because once event or under -- or once event is very rare event. When it -- when it happen, you need to have a system, really, which can be very robust and very reliable to deal with it because when it happen, there's a blackout. There is really a big system event to start with. So really, likely the -- where we are right now in the system, based on where we are and hopefully -- and that's where -- that's where our standard is moving, at least hopefully, to prevent us from being to that stage. So no event -- there is no event happen to support even any frequency, even 57 hertz, which is there in IEEE standard. It was -- we cannot -- we have no event to support that in overall system. Thank you.

MS. JONES: Hello. Rhonda Jones from Invenergy, and just building upon then some -- like, when you look at the 10 system disturbance events that were used in the analysis, it never came below 59. So just curious when the widened bands were established to also -- they considered current-day needs and a little bit of projection or forecasting for future needs. One of the things that I'm trying to work to reconcile is, currently, right now, the interconnection dynamics were considerations when you set -- when the bands were set in the past. And I'm curious how those unique dynamics were considered now just having one big band that covers everything versus consideration for tailoring the bands based on the interconnection dynamics.

MR. AL-HADIDI: Let me see if what -- if I understand your question about the reaction of the IBR or to -- how to recover from the frequency itself, and that's why the six second was giving the IBR time to respond to the frequency and try to -- because it has some time response. And in our standard, we did not come with a performance requirement, so it could be performed within four second, five second. It's much faster than synchronous machine to respond to the frequency event, so hopefully that in the future will be able to recover the frequency much faster. That's why we thought the six second itself is the time where it give enough time for the IBR technology to inject or remove power from the system to respond to the frequency event itself. I'm not sure if I got your question. Sorry if I did not get it.

MS. JONES: That was part of it, but I think the biggest thing I'm trying to understand is that the mix of generation in a specific interconnection does impact inertia and frequency performance.

MR. AL-HADIDI: Yeah.

MS. JONES: So I'm just wondering consideration for bands that are more accustomed to the dynamics of an interconnect versus just a broad, no matter where you are, this is what you need to do because there is some benefits to having it tailored in that way. You know, when you look at the events in the East versus the Western interconnect, the evidence is very distinct on where the concentration of some of those misses were, which are primarily contributed to settings, which is human error versus not being able to perform enough. Was just kind of curious about maybe tailoring the curves more to interconnection dynamics and generation mix as opposed to just a one-size-fits-all.

MR. AL-HADIDI: That could be an approach we could -- we could use. Actually, there's nothing wrong with that. It's the only thing which -- in my opinion, it's still -- there is a lot of unknown, and we know that systems going to change, and the way it change is going to be more and more sensitive to the frequency event. Load itself is significant. It's going to -- we have too much IBR load technology, which is going to come in, and some of these one actually the trip themself or remove themselves at certain voltage. If you start removing significant amount of load on and off, that will generate fundamentally very significant frequency change.

So really just to be careful where -- we thought we are -- a second part of discussion where the industrial is heading. Is it something which we -- if there is no actual limitation, what's the harm of getting there? There is -- if the cost is reasonable and it meets some reliability in the future and even some into the system, we thought there is maybe no harm. But if that's not case, we'll see how the thing goes with input from the OEM about if there's a concern or not. Thank you.

MS. CASUSCELLI: Thank you. One more question from online here. Can you discuss the data requirement in the measures?

MR. AL-HADIDI: Sorry. We didn't get the question.

MS. CASUSCELLI: Can you discuss the data requirement in the measures?

MR. AL-HADIDI: Data requirement is already established in the PRC-028, so PRC-028 established data requirement for the measurement

MR. VENKITANARAYANAN: Morning. My name is Nath Venkit, and I'm from GE Vernova, and my question is on the -- on the requirement that inverter-based-resources should not trip on instantaneous overvoltage, which I completely agree with. But the concern is that individual inverter-based resource units, based on the language in PRC-029 -- I believe, it's footnote -- or, you know, Note Number 10 in Attachment 1 -- should have a filtering for one cycle before they trip.

Now, I was part of the Drafting Team for IEEE 2800, and this was discussed pretty extensively, that standard. IBR-powered electronics do not have that kind of long duration overvoltage capability. So the compromise that was established in IEEE 2800 was that the one cycle filtering requirement was applied for any protection at the plant level that would -- that would disconnect the entire plant. For example, if you had an overvoltage relay, then you would need that kind of, you know, filtering.

However, for IBR units themselves, the standard did not just give them a blanket exemption. 2800 specified sub-cycle overvoltage Ride-through requirements that individual IBR units had to withstand, right? So it wasn't a requirement to wait one cycle before you trip for any overvoltage, but a more rational requirement for sub-cycle overvoltages. For example, the IBR unit would need to Ride-through and overvoltage of 1.8 per unit for one millisecond. So that's one of the requirements in IEEE 2800.

So the way PRC-029 is written, I think we really have only two choices, right? If you have a very large overvoltage that is imposed on power electronics, then you can let the inverter trip, protect itself hopefully, and come back online within a few seconds or a few minutes, or if you don't allow it to trip, then the choice is the inverter gets damaged, then trips and will take several months or years before it can come back online. So I would -- my question is, why is the requirement not more specifically calling out sub-cycle overvoltages for individual units to withstand?

MR. AL-HADIDI: We were there first. We have -- it used to be in this Draft Number 1. I believe it was R4, we're dealing with the transient overvoltage. However, we were -- basically even -- whatever we see right now in IEEE standard, they are having very difficulties would -- come with some mechanism how even to do the measurement and calculation for this transient overvoltage, and we felt that the industrial is not in the stage where it could have that -- the work based the PRC-028 and how the mechanism, how to calculate it. And it's -- we thought it could be very difficult to come with way to try to be measuring the compliance of that event.

The question will come, why the system -- why the IBR is going to see 1.8-per-unit voltage? Is it because of the switching within the IBR itself with some things a design issue, or is it from the system event? If it's from the system event, I don't believe there's any system event. The voltage can go transiently to 1.8 without impacting -- overall, you'd be -- you'd be with the filtering time of even one second one cycle, most likely that will lead to your voltage to be fundamentally above 1.2, and we could trip for the overvoltage.

We had a struggle on the technology itself, how to do the measurement, and that's why we feel there is the best way, try to move away from this requirement, become very specific, become challenging to meet the compliance part of it. And that's why we moved away and to remove it. And we compensated with a filtering to ensure that if it's a protection -- transient overprotection, then you have to protect it in this way. But if it was internal issue, you have the arrestors. You have different mechanism to deal with it, able to deal with the overvoltage during -- as a result of a switching within the IBR facility itself, so, and that's part of your design. As a design, that's part of it, but we were mainly concerned about the system event, and we did not see a way where we can capture system event for that reason.

MR. WANG: Yeah. I just want to add some background on the -- on that requirement, yeah. So in the IEEE 2800, right, that's the -- that transit overvoltage specify at unit level. That's the -- that's the -- I think that's the requirement.

MR. VENKITANARAYANAN: It is at the --

MR. WANG: Yes. For PRC-029, we didn't talk about the unit level. We just look at the POI, right, or POI in -- along with the IEEE 2800. Another issue, we -- the Standard Drafting Team deal with this. For the -- actually even the IEEE 2800.2, Subgroup 2 and 3, we had very, very lengthy discussions, yeah. If we supply that at POI, right? So let's do POI, the high set of transformer. Even the -- even the high set of transformer endurance, the experience of that high voltage, right, transient overvoltage, based upon the BOP of the plant, it's very complex. The issue actually to reflect back to the terminal, yeah, right?

That's the reason why we -- the Standard Drafting Team facing in the -- for the challenges, right? Even if we apply the highest -- high set of transformers that, say, like 1.8 per unit high voltage, it's very hard to identify what high voltage experience in a terminal. That's one -- another reason we remove that requirement to the Note 10 now, just based upon the previous event analysis, right? We just avoid, say, like, the -- just like (inaudible) suggest one, two points, yeah, just trip off the units. That's the -- that's the base -- the rationale at this point, yeah.

MR. VENKITANARAYANAN: Right. I understand, but I hope you understand there are only two choices. One is the IBR trips to protect itself and comes back online within a few minutes or seconds, or it gets damaged and still trips and is not able to come back online for several months or years. So with that, I'll end my question. Thank you.

MR. AL-HADIDI: The standard didn't go that far, and as I said, we don't have any measurement on the unit itself. Our requirement from PRC-028 is only at the high side of the transformer, so there is no mechanism to come with any compliance requirements for it. That's the reason we're -- where we are right now.

MS. CASUSCELLI: All right. So I need to issue a two-minute warning here, so I apologize to those in the room who can't ask their questions. So I'm going to ask one from online here. What measures did the Drafting Team take to ensure that IBR owners do not bear a disproportionate responsibility for system frequency response?

MR. AL-HADIDI: You have to Ride-through it. I'm going to say they have to Ride-through it. They need to Ride-through it. So it always need responses, same event, and their equipment needs to stay online, and the standard is not requiring them, as written right now at least, to provide a frequency support or any performance. So no performance compliance is just to maintain -- connect to the system and Ride-through the event itself.

MR. HAKE: Hi. Sam Hake with a AES Clean Energy. We're a renewable energy developer, and I'll try and keep this quicker. It's a little bit less of a technical question. So I wanted to focus on the language in R4 that talks about hardware-based limitations. We have some concerns that we have legacy sites that may have -- we may need exceptions based more on modeling information, either availability or quality of the models, in order to demonstrate and determine if sites can be compliant. So the question is, why is there that focus on hardware-based limitations in R4 that seems to exclude some, what we believe, valid software limitations?

MR. AL-HADIDI: It's for modeling or for the voltage, Ride-through, you mean to say, because this standard, it doesn't deal with modeling. Maybe I

misunderstood your question or maybe I --
MR. HAKE: So the language in R4 talks about exceptions for voltage Ride-through --
MR. AL-HADIDI: Yes.
MR. HAKE: -- based on hardware --
MR. AL-HADIDI: Hardware limitation. Yes, you're right.
MR. HAKE: Yeah. So my question is why hardware limitations only?
MR. AL-HADIDI: Okay. That also came from the FERC order. FERC order stated very clearly that any voltage exemption need to be based on the hardware equipment, not the software. So we tried to -- when we are constrained with some language, so we -- and we understood some -- and you're right. Some software could be very challenging to deal with, but we understood by "software," if something could be dealt with, if it's not really something which you couldn't update different or upgrade your software, it become really hardware limitation at that case.
So we left it open, what do you -- what you guys can come with the hardware limitation. In my opinion,

if you cannot do anything about your software because it's become hardware limitation where the version of it or the -- is not enough or it's not in capability to upgrade, it could become a hardware limitation, but this is my interpretation. It's not NERC or FERC. That's my opinion. Thank you.

MR. HAKE: Right. I appreciate that, and I think that's exactly the concern, right, is that it's open to interpretation.

MR. AL-HADIDI: Yes, you're absolutely right.

MR. HAKE: Thank you.

MR. BENNETT: All right. Thank you, everybody, for the wonderful questions, both in the room and online, but I think it's time -- we need to transition to our next presentation here, but before we do, let's -- our two friends here in the hot seat from the -- from the Drafting Team, why don't we just give them a round of applause real quick? They've done a great job.

(Applause.)

MR. BENNETT: So as they exit the stage, let me just tee this up for Alex. Our next presentation is a very similar subject, another review of voltage and frequency Ride-through criteria. So to walk us through this, this is Alex Shattuck from NERC, and yes, I did pronounce his last name correctly. So, Alex, please help us out with this. Do you need a microphone?

(Brief pause.)

MR. SHATTUCK: Thank you very much. My plan today was to present a bunch of objective facts. It seems like a bunch of y'all did your homework, and a lot of what I'm presenting, we've talked about through the questions and that kind of thing. So the goal here is to just present some information and some data and some observations without giving any opinions. If I give an opinion by accident, sorry. It's mine only.

I will read one recommendation. So I'm not going to give a recommendation, but I'll read a recommendation we've given to tell the story. So I'm going to try to tell a little story here. I was told to keep this high level. We might beep into the weeds a little bit. It's a Technical Conference after all. So with that, let's just start with the first slide.

I figured since we're getting it started here, something to look at would be fun. So we're going to start with why do we need Ride-through. Just to tell the story quickly, the GIFs here are from Texas A&M's kind of synthetic grid system. They do heat maps for voltage and frequency Ride-through. They present them with their kind of synthetic grid that they use at their facility or at their university. So this is just to kind of show, when there is a disturbance when something happens, it propagates around. If you look at the heat maps for frequency, it's not just one disturbance. It's moving all around, and it's really -- you can see the differences in what's happening, what deviations are happening based on location, based on the system they're at.

And this is just kind of the world we live with, right? Unexpected events, they happen. They're going to happen. They're going to continue to happen. Our job as an industry is to make sure that when they happen, we are -- we've done our homework, right? We've done it, we've done our planning, we've done our interconnection studies, we've done our modeling correctly.

Not every unexpected event is a major disturbance. You know, someone hitting a telephone pole -- or sorry -- utility pole and dropping a transformer is not going to cause a massive frequency deviation, but something like a -- an DESO-1 or DESO-2, we've seen, or a Uri, right? We've seen unexpected events cause significant deviations to the point that we have literal processes for tracking these things and reading these things and, again, reports out our disturbance reports.

So what do we do? We have to make sure that we reduce risk by making effective and efficient criteria. Efficient is kind of the -- I took this from our little circle. Efficient is the key thing here, right? We could probably make a system that is perfectly reliable, but that's going to be a tank when we might need a Toyota Camry, right? We can -- you know, there's always that kind of how much can you do with something that's reasonable or something that's efficient, and how do you hit your reliability with a certain level of risk averseness, which probably isn't a word, while still making sure that we're not making everyone pay thousands of dollars a month for their power bill.

So next slide, please, Levetra.

We'll start with just -- or I guess we'll continue with talking about what we've seen so far. Right now we have 10 published major disturbance reports since 2016. That's about 15,000 megawatts, and the last four years have been about 10,000 of those megawatts, so -- and about twice as many events. So if you look at two windows of time, we've doubled both size, total size, and we've doubled the frequency of these events, which means they're probably -- they're linked a little bit. The observations point to the fact that they're linked to penetration of IBR, right? If you look at the little graph on the bottom left, you can see the events, right? They're happening in areas that right now have some of the highest penetration of IBR. Major disturbances, those reports, those are -- those 10 reports are IBR related. There's been a few more of those since those last ones are out. We're in the RFI kind of data collection stage for those.

But that's not the whole story, right? There's also different technology. So the major events so far that we've given major event reports for have been solar PV and BES. That's not to say that they're the only folks that have problems, right? Most IBR technology's relatively similar outside of the hardware piece, right? There's software based, software driven, a lot of if I do something wrong parameterizing a PV, I probably make that same mistake, parameterizing a wind turbine in the software parameter sense, and we do have some data to back that up. NERC is working with Texas RE and ERCOT to make a wind report that shows and links to the causes of reduction of those previous disturbances. So that's to say that just because there hasn't been a major disturbance that was a wind -- I guess there was a panhandle disturbance, but there -- other than that, there haven't been that many wind-related disturbances.

It's not to say that the wind has no risk associated with it. Just preliminary, kind of off the top of my head numbers for that, it was something about 80 percent of the multiple thousands of megawatts unexpectedly tripping off wind in Texas, about 80 percent of those or 90 percent of those were for the exact same reasons that we presented in all of the solar PV and BES reports. So why are they not showing up? Well, they're kind of, you know, it could be at night, right? The faults happen during the day. Maybe wind isn't operating at full capacity like PV is. If I have a hundred-megawatt PV plant and a hundred-megawatt wind plant in the middle of the day, the wind plant's probably half-ish and the PV plant's at max.

So the same disturbance trips both of those off, same size plant, but the event for the PV is twice as big, right, because it's actually operating at max. So outside of those, we also have Winter Storms Uri and Elliot as far as, like, firm data we can pull from, and just those are the Uri and Elliot on the right side here. So if you go to the next slide, please.

All right. We'll orient ourselves with what I realized -- it's actually pretty clear. So we'll orient ourselves with what is out there right now, so, and what we're discussing today. So kind of I linked it to PRC-024, PRC-029, the draft criteria right now, and IEEE 2800, and they're all in the same graph here, and it's kind of a mess, right? Part of the mess is --

someone brought it up -- PRC-024 four has regional variances for -- different requirements for different areas, right? If you look at, you know, the draft PRC-029 and, you know Quebec's PRC-024 curve, they're pretty similar, but again, that's for a specific system with specific needs.

And also the mess of this, it's confusing, right? It's hard to look at that -- you know, if I'm -- if I'm interconnecting a facility, and I want to do it across the United States, and I want to be a developer, it's kind of confusing to know, you know, exactly where to find each criteria, exactly how to do each plant in each area and how we talk to each other. Reviewing the alert data, what we saw a lot of in ERCOT specifically was ERCOT machines have Western interconnection parameters, right, because they're similar developers, and they just put them on that one, right, because they're not the same. Unifying them can help, but there will always very likely need to be some sort of, you know, small variance or something to make sure that everything's reliable for everybody. There likely isn't any one-size-fits-all anything for everybody, but if you have a good starting point, we can adapt that to what we need for reliability. And what I did to kind of help with the rest of the slides and the comparison --

If you go to the next slide, Levetra --

I realize that's a typo. I wrote "most stringent," but it's least stringent. I took the inside of every curve to basically say if you were following the minimum or the least stringent PRC-024, that's what we're comparing the rest to. And when we talk about the events coming up, that's what we'll use to kind of use for a barometer. And it's much easier to look at these three curves versus, I think it was like nine on the last one.

So when you look at this kind of comparison, you'll see that -- a couple observations, right? Draft PRC-029 and IEEE 2800, they share the same continuous operation bands, so both of those standards are saying that for these bands of frequency, continuous operated. So that's an alignment that's good for the rest of the discussion after reading all the comments that we've gotten, but they deviate pretty significantly kind of specifically at the maximums in the short timeline.

So, I mean, if you look at kind of farther out in the 200-302nd range, we're not that far off. They're pretty well aligned. It's just this kind of first six seconds where we see the massive deviations both from 2800 and from the original PRC-024.

So if you go to the next slide, please, we can compare that to our major events.

So y'all stole my thunder a little bit here by doing your due diligence, which is great, but none of the major events -- none of the 10 major events we've released reports on were outside even the continuous operation bands. And if you look at the little -- the very small, very skinny yellow rectangle, that is the worst frequency deviation and time out of all of the events, and that's Blue Cut in 2016. And you can see that's well, well within both PRC-024, within the continuous operation bands, and it's well within both PRC 2800 -- or sorry -- IEEE 2800 and the draft PRC-029.

So this kind of shows us that for those types of events -- you know, keep in mind that these disturbance events happen somewhere around like system normal, right? So we might not see -- you know, we're not expecting to see a massive crazy change here. The system's about normal when these are happening. So what we get, because operators are doing their jobs well, because we have things to do and procedures to mitigate when these events happen, the deviations aren't that bad, at least from what we've observed. Things will change as we change penetration, but we'll have to assess the risks and how we get there and how we can kind of guess or study or estimate what they will need in the future. So this was system normal, major events. Again, this was the worst case. Very many of them were, you know, in the order of 10 to 30 seconds or something like that, so about the same rectangle shape but much, much smaller on the graph.

So all I have to say is that when we observe our major disturbances, we've got a little bit of leeway with everything proposed so far. So we're not like right up against anything at the moment, but all solutions seem to be viable as far as riding through the major event reports.

So if you go to something on the next slide, which is, you know, not system normal.

This Uri and Elliot. They're bigger, right? The rectangles are bigger. Elliot was, again, about the same-ish as the major disturbance reports. So the Blue Cut graph very skinny, not a very large deviation, somewhat long-ish. But the interesting thing is Uri, right?

So Uri, if you notice, it kind of kisses the purple curve there, and that corner of the purple curve is actually ERCOT's frequency Ride-through, so we were very close. I'd say folks are starting to put protection things directly on the curve, like we observed quite a bit of in the alert data. We were very, very, very close to seeing additional tripping because of frequency protection on the criteria, so, and if that would've happened, that would be the first time we've observed it.

The last slide -- you don't have to go back -- what the last slide said -- I said nearly all frequency-related tripping was due to mis-operate -- not mis-operations, but incorrectly set parameters, instantaneous measurements. None of those -- I wrote "nearly" on the slide to cover it, but none of those were based on criteria. You can see on the last graph, too, that they weren't anywhere close to the criteria.

So at this point in the past, right, the bounds, we haven't gotten close to the bounds of any of things that we're proposing now, except for 2024 in Uri, and Uri was a massive, massive event, right? So maybe we're at a point now with this data that, you know, we might know that we might need to improve upon PRC-024. What we do to improve on 24 comes from all the input we're going to get from our panelists, the OEMs and their capabilities from the system folks in what they want or need or desire, and what kind of information we need to show that, hey, I can't do this and I'm going to prove it to you or not, or what's sufficient proof, or how do we study things moving forward.

So all of this can hopefully -- I'm trying not to get into too many details. I want the panelists to tell us all the things from their mouths, different, from them. So this is just to show that if we look at our data, it's not a ticking time bomb. It's maybe a time bomb in construction, right? It's a -- it's not an immediate tomorrow problem, but it's maybe a something we should focus on moving forward. But again, both things we're proposing, or, you know, we're talking about through all the comments, the main topics we're talking about are 2800 and PRC-029. Both of those would have, you know, written through these events.

So if you go to the next slide, please.

Just to summarize, none of the events we analyzed were outside of the continuous operation bands. And the next bullet is something a little bit interesting, is that because of that, we have no benchmark event, right? When we did the GMD standard, they had -- you know, they say you make benchmark events. So think of an event or look at a past solar or flare event and see what's happened and use it as a basis for, you know, setting up your parameters. So we don't have a benchmark event, right? We've had disturbances. None of them are saying what you have right now is insufficient. So we don't have anything to base that on.

So, you know, say we had an event that was exactly the PRC-029 proposed curve, then that's great, right? We say, hey, we saw an event. We witnessed this event. Our bounds need to be outside of this event. So we all say online, well, the operators do their jobs and fix the system. We don't have that. We've also seen -- so with that, there's kind of three ways, right? It's a benchmark event, it's doing detailed studies into the future, or it's saying that give us the best you can do until we either hopefully never get a benchmark event or improve our study practices and data practices to have some meaningful forward-looking studies.

So looking at the data we're receiving in our Level 2 alerts, both modeling and IBR performance, and kind of the fact that none of the 15,000 megawatts that tripped offline were predicted in the model space, I don't know at the current moment if the industry's ready to say, hey, here's a study I'm going to hang my hat on that says here is the level of frequency Ride-through I can get my system to do and use it as a benchmark event, right? We need to improve our modeling, improve our studies, improve our parameterization, and then maybe we can trust that for something as important as setting these things.

So what you can do now is you have kind of two things. Either set your protection settings as wide as possible and show us that with data and not, like -- you know, show us that literally if you exceed this, you'll burn, right, or come offline or damage something, or come up somehow with some criteria that happens to be able to be accomplished by everybody, right? So at this point, those are the branching paths we take as far as, like, putting some data-driven decisions there, right? It's maximize --

And if you go to the next slide, please.

Maximize your settings or use those and feedback and that kind of stuff, just come up with bounds that are reasonable for everybody. Maybe some will be able to meet them, but if we have criteria where the number of folks who can't meet them is a number that we're happy with -- or not maybe happy with, but okay with, you know, operating the grid width, then we're moving the industry forward, right?

So this is a recommendation from our Level 2 alert on IBR performance issues, and I'll read this and then I'll tell you where it came from. And so, basically, what we're saying is expand your voltage protection setting as widely as possible and minimize AC instantaneous voltage dripping. So the instantaneous pieces of both of those bullets, there's language in the standard addressing those things. But again, frequency and voltage protection should be based on the equipment capability. We've been saying this in the alert. The reason why it's in the alert is that this is actually a recommendation that was in Blue Cut, the very first disturbance report. It's been a recommendation to expand as much as you can since the first event.

So it's very important to maximize your capabilities as you can because, otherwise, you know, you're leaving things on the table, right? It doesn't make any sense to, you know, have a certain frequency Ride-through or voltage Ride-through ability and then set your parameters, you know, 30 percent inside that curve, right? You're not helping anybody on the system for that. So that's why this recommendation is here.

This is the recommendation I was reading. It's published, so it's not my opinion, and, again, repeated in basically every disturbance report and the alerts. And it's not in the modeling alert, but it's been repeated, and it's kind of what we're saying is a good path moving forward.

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So what do we do, right? You got to balance, right? There's balance between what the system needs to be safe and what you can do with the things that are out there on the system, right? If we combine those two into a -- the Venn diagram I made, hopefully, if you use technical capabilities to inform what you can do to meet bulk power system needs, then you get effective and efficient criteria, right? If the bulk power system says I need 80 hertz per 10 seconds, and the IBR says I can only do 75 hertz per 10 seconds -- I'm picking random numbers to not get close to anything we're talking about -- then you got a problem, right? And then you would ask, hey, how many of you folks can't meet this, and you get a number, and if that's the whole system, maybe that's not a good criteria. If it's 10 percent, maybe you can live with that, right?

So when we talk about bulk power system needs, what are they, right? Ride through things so that you can fix it, right? Stay online while the operators do their jobs and restore the system, and be effective and efficient when we're reducing risks. So that's all the things in 901 data, modeling studies, all that kind of stuff. Those are the bulk power system needs, very high level and in two bullets only, and then you have to compare those things to how do you get that, right? If I have a new criteria and I see you must meet this, how soon can you put something on my system that meets it, right?

That's something that OEMs will talk about, I'm sure, is the development cycle for products, right? Usually requirements inform design of IBR, right? We used to ask for requirements all the time when I was at the OEM, you know, please tell me what you want so I can build it and give it to you. The problem is that takes a while, right? And nd if you keep changing things, right, if we -- if every other year we have a new kind of proposed thing, then it gets kind of hard, right, to make sure we're designing things. And if you keep resetting the cycle every couple years, we're just kind of, you know, we're wasting money, you know, IBRs become more expensive, power becomes more expensive, and it's just kind of a big technical thing the OEMs will really probably correct me on and expand upon.

Next, we also have hardware limitations at legacy IBRs. We're going to hear all about that, I'm sure, from all the panelists. The fact of the matter is, some of it -- some of the IBRs won't be able to Ride-through any criteria, right? There are IBR out there on the system now that don't meet PRC-024. There are IBRs that don't meet PRC-028 -- or sorry -- PRC-029. There are IBR out there that don't meet IEEE 2800. So whenever you have a requirement, if you look backwards, there's always going to be some level of equipment that can't meet it, and what do you do about that is kind of the answers -- is one of the answers we're hoping to get from the folks who are talking here.

And the last bullet here is that you kind of get some diminishing returns, the capability extremes, and I kind of referenced it a little bit earlier, is if, you know, say we're all buying a car. The speed limit is 50. All the cars I can buy go 50, right? But then someone says, well, you have to have a car that can go a hundred miles an hour. I'm not going to buy a car that can go a hundred miles an hour if the speed limit is 50, right? So the products are going to be designed towards what about their requirements are, and if you really expand those to the bounds of equipment limitations, you know, it might be very expensive to get that last extra hertz, right, or extra hertz of criteria, an extra couple seconds of time.

So really, that goes back to the effective and efficient and reasonableness thing, right, is probably if we set some parameters very wide, in a few years after the development cycle, people could meet it, but what does that mean? Is that, like, a $10 million wind turbine now because, you know, it costs $2 million to get it to 63 hertz, but, you know, 68 might be some crazy amount of engineering or design and all that extra work. So the balance here is very important, and it starts with the needs. Basically, it starts with the needs, and then you have to balance it with what can I do and what can I do for some reasonable amount of, you know, effort, resources, that kind of thing.

Next slide, please.

So for new equipment, so I'm going to talk about new equipment, and then we'll go back to legacy stuff. So for new equipment, criteria need to be reasonable when compared to current and future capabilities. So if everybody's designed for one thing right now and we go 10X that, it might not be reasonable, right? If everything's been designed for something, when we change that criteria to expand it, we have to make sure that it's at a level of expansion that keeps the grid safe while also making sure that we're not putting -- we're not going to make things cost an extremely large amount of money, right, because we're trying to meet these future capabilities and that kind of stuff.

So if criteria are outside of equipment capabilities, like we're -- we know we've gotten some comments about from our written comment submittal, we need lead time, or the industry needs lead time, right? It takes time to build a new inverter. It takes time to do research and testing and all that type of stuff to be able to build something that you can sell to someone to install, and they'll still give me input, but probably five-ish years, you know, a ballpark.

And again, testing time, right? So you design it and you build it, and then you test it to make sure that it can do these things. There's not that many test systems in the world that can handle a, you know, a giant wind turbine or a full-sized inverter. So there's lines from major companies to test these things, so that also adds into the lead time necessary, right? You got to build it and you got to test it to show proof that you can do it, right? We're asking for proof of what you can do. You can't do that without testing it and showing you Ride-through.

So the bottom bullet is in red, and we're leading into the panel this afternoon, but input from manufacturers is crucial, right? Those are the folks who know what's in the box, right? They know what's in the box, they know how you got to what's in the box, and they know what's possible within the same box and what it means to build a brand new box, right? So their input is very crucial to kind of do the balancing act that we need to do for the efficiency part of that Venn diagram.

So next slide, please.

So for legacy equipment, we'll go very quick through this because I want to leave some time for questions, but there's a bunch of different things you can do. So the easiest thing, software-based protection change, or software tuning to make your Ride-through a little bit better. For those folks who had a 65-hertz capability and set their protection setting at 63, software change, right? Put it to your capability that's in your software. That is relatively cheap and relatively easy to do. It could be free, sometimes it might not be, but it's significantly cheaper than hardware based.

So hardware based has kind of two buckets, right? It could be small, hardware-based retrofits of equipment, maybe a new transformer, maybe something -- you know, a new smaller piece of equipment that's going to be more expensive than a software-based solution, but it's definitely going to be cheaper than repowering the whole plant, right? So that kind of nuance in the timeline of resources necessary from left to right, that's going to be very crucial to hear from OEMs, right? What is a small hardware based? What are your thoughts about doing that? Maybe the generator owners could answer that. What are you comfortable with? You know, at what point does a retrofit turn into a repower, right, and at which point does that mean you're not going to operate your facility anymore? Those are the types of balance and things that we need to hear from industry and from the OEMs to give us this information so the Drafting Team can update the language to make sense for all of us.

So again, I think this is the second of three times I wrote that. Manufacturer input is very critical, right? Diesel documentation, sharing the documentation, having it ready for folks to read and review, very important.

So next slide, please.

And this is my engineering slide. There's no pictures, and it's four bullets and, you know, four sub-bullets, five sub-bullets. Figured we'd want one big text wall for us. So are exemptions necessary?

I'm going to really leave this up to everyone else to talk about, and I would just keep it real high level. So we all know some amount of IBR may not be able to meet any of the proposed criteria or current criteria because they were installed before current criteria was made. Again, software-based upgrades could be a simple path -- simpler path. Additional considerations that are needed for software upgrades are not sufficient, so if I can't just set it back to whatever, what else can I do? How do we do it? We need to put for that. That's very important.

But the third bullet here is that exemptions could allow legacy equipment to remain connected while maximizing capabilities, but then there's like a giant burden of proof for that, right? It's going to take more than someone saying, my manufacturer said they can't, right, and they attested to this, right? That's probably not sufficient as far as documentation, right? We're looking for things like show us a curve that, you know, shows you're going to damage something. Give us documentation that your software-based protections aren't sufficient, right? New software can't go into old equipment maybe sometimes. Maybe it's firmware limited. Maybe they're already set at their maximum capability, right?

And then we need someone to be able to review these to assess risk and to basically see if they're true, right? If someone says, hey, I can't do that, and they won't give you any documentation, then it's hard for us to take that as, you know, a firm piece of validated data to make a massive decision, like changing Ride-through parameters for everybody. So what we can say, and I think this is pretty not contentious, is that, you know, blanket exemptions with nothing, right, blanket exemptions for everybody who asks for one is likely not as sufficient solution, right? So exemptions, if we get there, if the input leads us to that path, which they may or may not, they're going to have to come with some data to back it up.

So next slide, please

So we do have some data. The data is from the Level 2 alert for IBR performance. Keep in mind this was just solar PV and BES, and I realize that the numbers are super small. So the first piece of the data is that about 70 percent-ish of those folks who gave us their frequency protection settings said that they were not based at the maximum hardware capability. So we have reported data that says about 70 percent of the IBRs out there right now can do some sort of software-based something. Is that software based something big enough to meet PRC-029? The manufacturers will tell us. So we do have some room to make some adjustments.

What we also have is they gave us their protection settings for their inverters, and I didn't want to give, like, real megawatt values, but I put them in percentages. So this pie chart is all of the settings that were given to us where they said that they were at their maximum capability, and I'm going to walk up here and read it because I can't see.

So if you look at this thing, this is the -- all of them are within maximum capabilities, and we start with PRC-024, so this is the small blue chunk. Seven percent of what's been reported to us is within PRC-024, so current requirements, about seven percent are reported inside that. The next biggest chunk, about 32 percent of those inverter settings are within 2800, which means that, if the data is true, right, if the data they gave us is right, and they're at their maximum capabilities and that's what they're at, then we got about 30 percent of what's out there right now within 2800, which is somewhat actually in line with the data we got back from some of the folks who submitted that to us in writing with real numbers.

So the big chunk is things that are within PRC-029, right? Sixty-one percent of the total maximum are within PRC-029, and that makes sense, right? As you make the curves wider, fewer and fewer equipment are going to be able to meet it, right? So as you make things wider, we'll have to -- we're going to have to deal with a large number of potential hardware-based solutions. And what that number is and where we land in the spectrum of curves is going to be dependent on what we can do, what we're happy with not meeting criteria and what we do with those things.

So this is just to kind of quantify and to show that it's very important to pick the right, you know, criteria so that we don't end up with, you know, a circle that says a hundred percent of equipment can't meet it, right? We don't want that at all, but we got to pick -- the onus is on us the Drafting Team and as an industry to pick some criteria that we are happy with the things meeting and happy with the things that can't meet. And potentially, like we've discussed, you know, documenting limitations and providing that as evidence to be used for drafting decisions, right, and that kind of stuff.

So next slide, please.

I'm going to go very quickly so we have some questions time. So manufacturer challenges, they're going to talk about it in a moment or after lunch. So new IBR, what criteria to build for? How do you procure test locations? Long lead times. And again, at the extremes, right, the capabilities get really expensive, right? The extremes of anything get really expensive. For legacy equipment, hardware limitations, software solutions might not be sufficient, and legacy equipment was tested with applicable criteria in mind, right? So there's actually a decent number of stuff out there that we don't know what the -- we don't know what it can do because it was tested for PRC-024 or slightly more than PRC-024.

It's never been tested and it's likely that it's never going to get tested, right? You're not going to, you know, take down a wind turbine and drive it to Europe or maybe been a boat or a plane, right, and put it in a container and test it. So there's a lot of unknown there as well, and coordinating and implementing effective solutions is difficult, obviously, right? We're having this conference. This isn't -- has not been easy for any of us to kind of agree on and get a solution ironed out, so it's difficult for all of us.

Next slide, please.

So industry challenges: deciding which equipment will be needed to meet new requirements, getting evidence that equipment can or can't meet, communicating technical details to everybody. How do you do that, how do you post them, what are you posting, and that's for new equipment. For old equipment, how do you manage stuff that can't do it, right? How feasible is the software solution? How hard is it to get data? Apparently very hard. We learned through our two Level 2 alerts, both of which had the first ever extensions of deadline, it's hard to get data. And we were asking for things we're talking about today, protection settings, and we gave about 90 days, a hundred days for that, and we had difficulty getting protection settings in that time.

We've extended the deadline again, so we feel industry's pain. We know it's a thing. It's hard to get data. The data's really specific and really technical. If you ask the wrong question, you might get data that looks good, but it's wrong, right? So it's very difficult to communicate all of that forward between all of us and to get to a solution where probably no one's happy and then we'll know we did the right thing.

So next slide, please.

So key takeaways, another big red bullet at the bottom. I've said all this before, but manufacturer/industry input, extremely important to know what we can and can't do. We are recommending or we have recommended for eight years now to maximize your Ride-through capability. Documentation that's validated and accurate is difficult to obtain but will be critical moving forward.

Next slide. I think that's it. Great. And we have eight minutes for questions, but it's my birthday, Manish. Be nice.

(Laughter.)

MR. PATEL: Well, where is the party tonight then?

(Laughter.)

MR. SHATTUCK: We can talk later.

MR. PATEL: All right. So, Alex, great presentation. So couple of thoughts. You know, you compared PRC-024 with IEEE 2800. That is absolutely right thing to do. And then another thing we can actually do is actually compare PRC-006, which is under frequency load shed standard, and it requires transmission planner/planning coordinator to design in the frequency load shed programs, such that frequency does not go beyond certain thresholds, right? And as far as the generator Ride-through capability is just outside of those thresholds, we are good, unless --

there is a thought out there that, oh, wait a minute, in future we are going to allow transmission planner/planning coordinator to go beyond the thresholds in PRC-006 right now, right? So this is -- this is another data point that, okay, if the transmission planner and planning coordinator is never going to allow frequency to go beyond certain thresholds, then what's the point in requiring a Ride-through from a generator, right? Okay.

So then you presented hurricane -- not hurricane -- Winter Storm --

MR. SHATTUCK: Uri.

MR. PATEL: -- Uri, right?

MR. SHATTUCK: Mm-hmm.

MR. PATEL: So NERC's -- it's a good comparison. I just wanted to point out that that is actually not very appropriate because that event unfolded over many, many, many minutes, right? I think, if I remember right, 30 minutes or so.

MR. SHATTUCK: Mm-hmm.

MR. PATEL: And actually, NERC System Protection Control Working Group ended up writing a white paper saying, well, look, we cannot design PRC-024 or PRC-006, which is automatic under frequency load shed standard to something that happens over tens of minutes. Those two standards, 006 and 024, are for things happening in matter of seconds where operator has no time to blink, right? So anyhow, that was good comparison, but I think it's a little bit of apples and oranges.

So anyhow, going back to we have to look forward -- figure out a way -- for path forward, I think we could take an approach that is taken in PRC-024 and 006 that, you know, for certain regions, the requirements are a little bit more stringent than other regions, right? So when we wrote IEEE 2800, those who don't know, I was a vice chair. My middle name is 2800 nowadays. I get bad rap quite a bit.

(Laughter.)

MR. PATEL: And I'm also proud -- I'm also proud sometimes saying that, you know, we didn't know what is the right answer, so we flipped a coin five times and decided which way to go. But so when we wrote IEEE 2800, what we did was, well, we don't want to write a standard that is based on most stringent PRC-024, right? We wrote a standard that met two largest interconnections, assuming that for two other regions, there might be a reason to require slightly more Ride-through capability, and those two regions will write their own variance of it, right? So I think that's the option we could consider is can we take different Ride-through capability for different regions. I guess that was not a question, a comment. Thank you.

MR. SHATTUCK: Thanks, Manish. Yeah, there certainly is precedent for having different curves. It's in 024, and it is a possible solution to move forward.

MR. KAPPAGANTULA: Good morning. I understand I'm standing between everybody and lunch, so I'm just going to make a quick -- a quick comment on one of the slides that you had that talks about software changes are being a little bit cheaper than hardware changes. That that may be true, but just understand that software changes are not necessarily cheap.

MR. SHATTUCK: Mm-hmm.

MR. KAPPAGANTULA: As an example I could give you, just to make some software changes on one of our battery projects, we got a code of nearly a million dollars, right? And so when we're -- when we're talking about something is cheap, it's probably going to be relative --

MR. SHATTUCK: Mm-hmm.

MR. KAPPAGANTULA: -- very relative. So I just wanted to point that out that, you know, just because we're saying we can change software on some of these things, that it's going to be cheaper is not true. And then you also have to factor in the points that, you know, if you made a software change, you have to figure out how the rest of the equipment would react to that software change and if the rest of the equipment can actually support, you know, making that software change on just an inverter, for example, right? So I just wanted to make that clear and take into consideration when we're saying, hey, software is really cheap.

MR. SHATTUCK: Yeah.

MR. KAPPAGANTULA: The other piece also is when you're changing some parameters, that may not necessarily be a software change. So there's a lot that goes into it, so let's not uniformly say that the idea of, you know, we can make a few tweaks here in the software and that's going to just do the job. It's not true. That's what my technical experts are saying.

MR. SHATTUCK: Thanks. Yeah, everything was presented as relatives, right? And the OEMs will give us the details after lunch. I don't want to speak for those folks, but they'll give us probably some real --

MR. KAPPAGANTULA: No, I'm, I'm looking forward to that, so I would rather hear from them saying, hey, software is not cheap --

MR. SHATTUCK: Yeah.

MR. KAPPAGANTULA: -- than me just saying --

(Laughter.)

MR. KAPPAGANTULA: -- yeah, because you can tell us what you charge, too. I'd appreciate that.

(Laughter.)

MR. ROGERS: Yeah. So real quick question. You showed us the curves that had the, you know, frequency excursion events that we've witnessed within them and plotted, and we touched up against one of them. So that was, you know, the actual, you know, what we witnessed with the frequency. But another part of the -- you know, one of the contentious points of this is the rate of change of frequency.

MR. SHATTUCK: Mm-hmm.

MR. ROGERS: You know, we're looking at 5 hertz per second in the proposed language. What have we witnessed in these events as far as rate of change, of frequency that, you know, really drives to the need for that 5 hertz per second because, you know, that's one of the issues, especially with the legacy equipment. Rate of change of frequency wasn't even a design consideration. It's not that, you know, it's not set high enough or the parameter's wrong. It wasn't a thing. Whenever a lot of this stuff was built, you know, it just wasn't a consideration. So what are we looking at as far as an actual need based on the evidence for the rate of change of frequency, or is that even something that we have the evidence to speak to yet?

MR. SHATTUCK: Yeah, great question. I don't think I have that data. I don't think we have that recorded data. We have the frequency traces, but it's that, like, SCADA data granularity, right? So that's -- a specific data point we don't have at the moment. The only kind of information data points we have on ROCOF is -- that's rate of change of frequency for everyone else -- is, you know, international building standards or equipment standards that are used in a lot of IBR equipment facilities, right, the non-IBR pieces, the transformers, the other pieces of equipment. The data point we have for those are the, you know, the standardized ROCOF requirements, so, like, that's the only thing we really point to because we don't have the data from the actual events.

MS. CASUSCELLI: All right. I think we've got a hard stop, but maybe time for one online question. So software expansion study and accurate models are required. How will NERC support when standard models are required and when they are often not able to represent most IBRs?

MR. SHATTUCK: Great question, yeah. So I would -- I would like to point everyone to NERC's published that modeling guidance, which says that if you want to do something like a detailed study, right, an interconnection study, a study on your own facility to evaluate your design, for a local reliability study, if I'm Texas -- oh, that's a bad example -- that's a bad example -- if I'm New York studying New York, we are recommending user written models, equipment-specific, manufacturer-specific models, we're aware, right, obviously that many folks can't submit them. They're not allowed. But I would point also to FERC Order 2023, which says to submit both the standard library model and a user-defined model. And, you know, we totally recognize that if we're using a standard library model, we're not going to be able to represent most of these things we're talking about, specifically the detailed protections and that kind of stuff.

So we're recommending to use those more detailed models specifically for what was in the question, right? We know that what's out there is insufficient. Nothing's been captured, right? Nothing's been predicted, none of the major events. There is -- that's why we have a modeling alert out right now, right? The idea is to raise the floor of study work-through, you know, proper use of more detailed models where appropriate, not to say that standard library models have no place anywhere. But if you care about the result, if you want it to be accurate, if you want to be able to take that study and put it into a product or vice versa, you've got to use something more detailed like a -- usually a defined equipment-specific model.

MR. MAJUMDER: Rajat Majumder. Thank you so much, Alex. This is music to my ear, but I'll just make a very quick comment. You just said some people may not be able to provide that. The flip side is most of the major ISOs do not allow it. That's the -- that's the problem. I mean, manufacturers are on the -- on the room. They can tell. I haven't had much trouble working with any of the leading manufacturers not being able to provide the model. They can, but their hands are really tied with certain ISOs, and it's going to that direction. We have many problem trying to convince those ISOs that they should use the user-defined model, not rely on the generic model. So please be aware of that. It's not just from the OEM. It is the ISOs who are not allowing it to make that happen.

MR. SHATTUCK: Will do that.

MR. BENNETT: Okay. So it appears we've come to the end of our discussion for now, so, Alex, thank you.

MR. SHATTUCK: Thank you.

MR. BENNETT: Great presentation. Very informative.

(Applause.)

MR. BENNETT: So with that, we're here at noon Eastern Time. We're going to take a one-hour lunch break, so we'll be back at 1:00 Eastern. As for online questions/comments, if we did get them addressed right now, they are going into kind of an archive folder, and we'll circle back to them at another point of our Technical Conference over the next day or two. So they're not gone. They're not forgotten. We have them, and we'll bring them up as appropriate.

And with that, I think we'll take a break. Lunch is just around the corner, and we'll be back at 1:00.

(Luncheon recess.)

MR. BENNETT: Okay. So I'm showing 1:00 here, and it looks like we have most everybody back here in the room. So for our online participants, I think we're getting ready to start.

So this will be our first pan of panel discussion of the day on "OEM Perspectives on Voltage and Frequency Ride-through Criteria." So to walk us through that, we have Standards Committee member, Charlie Cook, from Duke Energy, as well as Alex from NERC here to help us through that. So with that, I'll turn it over to the panel.

(Sound checks.)

MR. COOK: Good afternoon. My name is Charlie Cook. As Todd said, I work for Duke Energy, but today I am here representing the Standards Committee. Alex?

MR. SHATTUCK: All right. My name is Alex Shattuck. I'll get my stopwatch ready for everybody because we're going to keep everyone on a two-minute time per question, so making sure we keep track.

So my name's Alex Shattuck from NERC. You heard from me just moments ago, and I guess we'll just jump right in if you want to ask -- get us started with the first question.

MR. COOK: Yeah. Could we have the panelists, starting down at that end, please introduce yourself? Tell us a little bit about yourself and who you represent today, again, keeping an amount -- I'm sorry -- keeping in mind that we are time limited, so.

MR. SCHMIDT GRAU: All right. My name is Thomas. I'm representing Vestas. I've been with Vestas close to 15 years, and I'm heading our Power Plant Solutions Group that covers everything from development, sales, construction, and service, and it includes every single topic related to grid interconnection and reliability.

MR. KARPIEL: Scott Karpiel, SMA America. Been in renewables for about 15 years with various different OEMs. Hope to bring kind of a broad spectrum of knowledge and expertise to the panel and the committees here today, and thank you for having me.

MR. KOERBER: Arne Koerber. I'm representing GE Vernova, and specifically the wind side of GE Vernova, and we also do other things. I lead the product line team for controls and software, and a lot of the discussion here today was around software and controls, so that's why I'm here. Been with GE 15-plus years in various roles around controls and software.

MR. DAHAL: Good afternoon, everyone. I'm Samir Dahal. I represent Siemens Gamesa on source side. I'm responsible for model integration, parameter rises, and for all our (inaudible).

MR. PATTABIRAMAN: Hi. My name is Dinish Pattabiraman. I'm a development engineer here at TMEIC Corporation, Americas. I work on modeling of our inverter-based resources, you know, meeting grid requirements for various ISOs, and analyzing grid events and finding solutions.

MR. COOK: Thank you. So the way we're going to do this today is I'm going to ask the first question directly to an individual, and then I'd like -- so I'd like the rest of the panels to pay attention and listen, and then if you have anything significant to add to what has been presented already, please do so. We'll give you each chance to comment.

So question one says, do you anticipate challenges with your equipment meeting the voltage Ride-through criteria as specified in Attachment 1 of the draft PRC-029, and there are three subparts to that. First of all being, if you do so, do you have an estimate for how many products will be affected? Second part, how does the estimate change when considering IEEE 2800? Third part, how does the estimate change when you consider PRC-024 boundaries? So I'll direct that question first to Dinish.

MR. PATTABIRAMAN: So for TMEIC inverters, especially inverters existing in the field, you know, we won't be able to meet IE 2800 at this point. For newer inverters, we'll be able to meet IE 2800 requirements. Coming down to PRC-024 requirements, most inverters in the field can meet PRC-024 requirements. Newer inverters, obviously, we'll also be able to meet it. But in terms of parameterization, we won't be able to eliminate parameterization for some older generation products.

For PRC-029, based on the language that is written, none of our inverters will be able to meet the requirements, especially given that there are requirements such as instantaneous or voltage protection should have at least one cycle of filtering. That's something that we wouldn't be able to meet even for all inverters.

MR. COOK: Starting down at the end, anything else to add, specifically, would you or would you not be able to meet the requirements?

MR. SCHMIDT GRAU: Repeat that one.

MR. COOK: Okay. It says, do you anticipate challenges with your equipment meeting the voltage Ride-through criteria --

MR. SCHMIDT GRAU: Yep.

MR. COOK: -- as specified in Attachment 1 of the draft PRC-029?

MR. SCHMIDT GRAU: No. Only for Type 1 and Type 2 turbines, which is very limited install base in U.S. And we do see end of life cycle in the near future and potentially be powered to different projects. For the Type 3/Type 4 turbines, we anticipate to meet the requirements for Ride-through requirements for PRC-029. Those requirements are also aligned with the new design philosophies and also with the IEEE 2800.

MR. COOK: Okay. Thank you. Next, please?

MR. KARPIEL: So future, current, previous generations of our inverter stations, I have no problems with the voltage Ride-through. The legacy stuff that's going back 10 or so years, clips a little bit of a corner on one of the Ride-through corners, but then with the exemption, it shouldn't be a problem.

MR. COOK: I'm Sorry. Could you clarify that about the exemption? What was that statement?

MR. KARPIEL: Well, does it not state for voltage that there's an exemption?

MR. COOK: Yes. Voltage, yes.

MR. KARPIEL: Yes.

MR. COOK: Okay. Just want to be clear. Next.

MR. KOERBER: Similar to my colleagues here, I think we have to really split this between new products that are under development and the installed base. For new products, plants are generally aligned with IEEE 2800, so we're evaluating what's the difference. What impact does that have for the installed base? We do expect that the majority of the installed base does not meet these voltage Ride-through curves. Some cases might be close. In some cases with a project-specific evaluation, voltage drops across the collector system, it might be possible to meet it, but on paper and curves taken strictly as stated, we do expect that the majority of the installed base does not meet those curves. That's on the curve.

And then it's important to point out that Attachment 1, Items 9 and 10 have additional requirements that weren't previously requirements. We've already had a quick discussion this morning on the instantaneous voltage and on multiple fault Ride-through, and we do expect both of those to be challenges for the installed base.

MR. COOK: Thank you.

MR. PATTABIRAMAN: Yeah. We have a similar comment as our colleagues with G. For legacy turbines, we can Ride-through the curves, just the curves, with software, unlimited hardware upgrade, but items listed in 9 and 10, multiple Ride-through instantaneous, that's not something that we've been tested and evaluated, so that would require a thorough investigation from our part. And the testing part, like it has been brought a couple of times, there is a possibility for legacy turbine to be retested against the newest standard is, I don't think that's going to happen.

MR. COOK: Okay.

MR. PATTABIRAMAN: We will have to ask for exemption on those.

MR. COOK: Thanks.

MR. PATTABIRAMAN: But for the new lines, we would completely design our product to comply with IEEE 2800.

MR. COOK: Thank you.

MR. SHATTUCK: So I guess most of us are wind, right, here. So we're missing our estimate participant, but I guess, Dinish, since you're the --

(Side conversation.)

MR. SHATTUCK: All right. So for y'all's perspective, like, what's the -- kind of similar responses with some varied, you know, actual numbers, but what are the main differences for kind of the failure to meet or challenges between wind and solar, you know, just the technologies as a whole themselves? Like, I guess what are the limiting elements when we say something can't meet one of the requirements? Is it -- is it a software? Is it a hardware? Is it old firmware? Is it a specific piece of equipment?

MR. KARPIEL: So for PV and BES, battery energy storage, it's both, right? There's a hardware limitation as to how long the holdup -- the backup for the communications and everything can withstand. So whether they're using a battery, a UPS, a super cap, or whatever they're using to have that buffer installed, so that's a hardware limit -- that could be a hardware limitation.

And the other one is parameterization, right, the software that's the firmware that's used in inverter technology. Amongst the experiences that I've had with the different OEMs and legacy products here at SMA is the firmware has a limitation of how far it will allow you to Ride-through in amplitude and time. That's usually set by some other kind of hardware limitations so you don't damage the equipment. So I can't speak necessarily for the wind side of things, but for the inverters, the PDs and better energy storage systems, it's a combination.

MR. SHATTUCK: Thank you.

MR. PATTABIRAMAN: Just to add to it, yeah, the same. It's pretty similar reasons. It's both software and hardware for at least the Ride-through curves by themselves. In terms of other requirements that are -- I think the gentleman from GE also brought this up before -- the instantaneous overvoltage protection, having one cycle of filtering is something our hardware cannot do. You know, IGBTs have very limited voltage handling capability, so having a one-cycle requirement significantly exceeds the capability of our products.

MR. SHATTUCK: Thank you.

MR. DAHAL: I would like that for wind especially. You have so many components inside the turbine, right, converter/inverter being able to do something doesn't necessarily mean the turbine can hold can do it. So for us, software limitation is there, and there is also hardware limitation. For us to be certain that just because converter can do it, you know, we are not going to be comfortable telling wind turbine as a whole can do it, right?

And also, when we are talking about software parameter parameterization, we cannot forget about the models, right? Every time the software gets parameterized or firmware get updated, corresponding model is expected to be provided, and rightfully so, right? For our legacy turbines that have been operating for 20 years and no longer in design phase, models were provided when they were first commissioned. I don't think anybody actually started using those models and providing feedback to us, so we saw no reason to update those models. Like, for the legacy turbine, we do not have any reason to keep them updated since we never got a feedback on a -- if there is any need to be updated. So all of a sudden asking not only to change the parameters, but also provide the model in a reasonable time -- updated model in a reasonable time that works with today's simulation environment, it's going to be a huge challenge. I mean, it can be done, but it's going to take a lot more than six month or a year.

We have -- we currently have closer to 15, 16,000 units installed, right? Each of those turbine might not have the same firmware. I know it. They don't, right? And also, our customers or the assets owner do have some flexibility on changing the parameter as they deem necessary, you know, based on their field experience or what have you. That information we do not have. So there is significant challenges just to provide a -- you know, to meet the new standard with those software or, you know, hardware parameterized, and I don't want anybody to forget that, you know? Yeah, you can -- we can do it. Parameterizing software can be done in, let's say, a year, but getting our corresponding model will take a lot more than that, yeah, especially validating as well.

MR. SHATTUCK: Thank you. The mic was off, but they said, especially validating those models, and I'll ask one more follow-up before we go to the next one. Sorry. Thomas, did you have something?

MR. SCHMIDT GRAU: Yep. No, and even if we have the models available, often that's -- to Rajat's comment earlier, ISOs and utilities don't allow those models to be used that is accurately representing studies for the -- evaluating PSE, so that's one of the challenges. We have -- we, to some extent, can do software upgrades and pure parameters with our software, but we are not able to do the evaluation of what parameters are required for that specific site because the utilities often don't allow us to use the right models for that evaluation.

MR. SHATTUCK: Thank you, and I'll ask, I think, the last question. The end of this might be a little faster, so we'll dig into some details here. One more detail question. So we talked about kind of the inverter/converter in the turbine in the -- in the inverter. What about balance of plant equipment? So this is a -- you know, it's a resource standard, right? The IBR must ride through, so are there challenges in balance of plant equipment as well?

MR. SCHMIDT GRAU: Yes. So if we look at the frequency response, that's where -- there's no design standards as we are aware of, that designs for plus/minus 4 hertz per six seconds. So you will see cooling systems and substations be affected. You have all the different equipment and the turbines being affected. It's not about the inverter. Inverters have some flexibility, but we cannot forget all the auxiliary component sensors, cooling systems, relays, protections, transformers, that is not designed for plus/minus 4 hertz per six seconds.

MR. KARPIEL: And let's not forget the medium voltage transformer that comes with the inverter station. Those situations that have high voltage and low frequency, you'll put your magnetics in the saturation, right? Saturation causes heat. Heat causes breakdown. So we have to be looking at the whole picture, the entire balance of plant to ensure that the inverter-based resource unit -- I know there's a lot of talk about what that definition is, but the station itself needs to be able to ride through 299 seconds, 660 seconds of this voltage or that frequency. And it has to be looked at by the OEMs going back throughout all the legacy, all the generations of their product, not just the current and future. So there's going to be some gaps that are going to happen in the technology.

MR. DAHAL: I also want to bring attention to the concept of repower, right? Like, we're talking about this and talking about repower. The repower that we've seen so far have been efficiency driven, right? So repower happens because you want to get more power out of the old turbine, not necessarily the electrical -- new set of electrical performance. We retain the main brain converter/inverter system, cooling system as it is, just change the rotor from the wind side. So just the term, "repowering," doesn't mean what you guys are thinking about repowering, you know. Oh, you repower, you get new set of performances from them, and that's not true at all. The market is not there for that to happen. The repower project that we have done so far has been purely mechanical repower, and it is very essential to consider that as well.

MR. SHATTUCK: Thanks. Is that the same for solar?

MR. SCHMIDT GRAU: Oh, sorry. Maybe also to add to that, even if you do a full repower in a cell and hub from one OEM to another, it's often older technology that gets installed because the tower, the foundation, and structure is not built for the latest rotor sizes in inverters, so that even if you are able to fully repower, it's still going to be legacy equipment that's going to be repowered.

MR. PATTABIRAMAN: Just answering the question on the balance of plant equipment. There are surge registers that are also included in the design of a typical IBR plant. They're typically located at the end of a feeder through wide overvoltages, absorb overvoltages, and so on. And the problem is that these sites are already designed with certain energy levels for these protectors and surge protectors, and any level of higher overvoltage could physically damage these protectors. But that kind of also includes instantaneous overvoltage, like I said earlier, is that, you know, having a one-cycle delay could basically be the difference between damaging and not damaging these arresters.

MR. SHATTUCK: Thank you. All right. I think it's time to move on to our next question, which is the same question, but for frequency but just one tiny piece to add in is we mentioned transformer saturation. There's other things that happen when the transformer saturates, like harmonics or SSR, which aren't necessarily this specific Ride-through, but they're not particularly good, friendly phenomenon, so causing that saturation somehow is not always great for the BPS as well.

So we'll jump into the next question. Again, it's the same question but frequency. So we'll ask it to Arne, and we'll go down the line, but do you anticipate any challenges with your equipment meeting the frequency rate through criteria, as specified in Attachment 2 of Draft PRC-029, and then the same kind of sub-bullets, yeah, estimates for how many products for 029 and 2800 and PRC-024? So we'll go with Arne first and go down the line, yeah.

MR. KOERBER: Yeah. And for us, there's about -- preliminary analysis looking into this, we estimate there's about 20 gigawatt of installed capacity. These are some of the oldest units, substantially before 2014. That would not meet the frequency Ride-through requirement if comparing against the S-design curve. What it would take, not in a position to comment on this. It's about 20 gigawatts installed capacity, and the answer really doesn't change whether it's IEEE 2800 or PRC-024.

MR. SHATTUCK: And that's for legacy. It's all -- that's all --

MR. KOERBER: Yeah, legacy.

MR. SHATTUCK: We'll go down the line. Same path forward, yeah.

MR. KARPIEL: So for SMA, the frequency Ride-through requirements are not an issue for our inverters as well as our inverter stations and the magnetics that are on the unit, and that's going back to all -- even our legacy equipment, and it doesn't change, right? The frequency curve for 029 is larger than the 2800 or the 024, so if we can meet 029, we can meet the rest.

MR. SCHMIDT GRAU: I might've jumped the gun a little earlier before, but, on the frequency. But for Vestas, we cannot meet the frequency plus/minus 4 hertz per six seconds on our legacy turbines, and that's the installed fleet in U.S., I think around 15,000 units. And it's not in design consideration for any new products, and that's simply coming due to ancillary equipment in the turbine. There's no design process standardization for any, like, sensors, transformers, relays today that is meeting that. It will also potentially have cascading effect causing reliability issues if you have a frequency that is plus-4 hertz, minus-4 hertz for that long duration of other loads and things in the grid going offline. So we don't have it into consideration of design as there's no suppliers in the industry that can meet that today.

MR. SHATTUCK: And sorry. You said 15,000 units. Do you have a megawatt estimate for folks?

MR. SCHMIDT GRAU: I will find it.

MR. SHATTUCK: Okay. Thank you.

MR. DAHAL: I second Vesta's response to that. Our legacy turbines cannot meet PRC-029. We have not considered PRC-029, those curve for six second in our new design either. So as of today, we have no product that will meet -- that will comply with PRC-029 frequency Ride-through in its entirety. Regarding IEEE 2800, we meet our newer turbine and our legacy turbine with some software and hardware modification, mainly software. We will be able to meet IEEE 2800.

MR. SHATTUCK: With all legacy or with all your legacy equipment?

MR. DAHAL: Except for Type 1 and Type 2.

MR. SHATTUCK: Okay. Yeah.

MR. DAHAL: Type 2 and Type 4, yes. And then our restrictions comes from -- for whatever was mentioned already. We do not have motors that we can source that will be able to Ride-through all the ancillary equipment, you know. I think if you look at what other IEC requirement, IEC 60034, IEEE 50-1, they all have plus-3/minus-5 requirement for these motors, and that's what -- you know, that is in line with IEEE 2800, and that's what our design philosophy is. And let me also add our -- it'll probably come later, but design cycle -- design-to-market cycle is five years for wind turbine. So any new standard that has that much of an effect needs to be given at least five years, if not more time, to be applicable. And if it's, you know, cost prohibitive or anything like that, then that's going to be another issue.

MR. SHATTUCK: Thanks.

MR. PATTABIRAMAN: So for older TMEIC inverters, especially thousand-word inverters and before, we have hardware limitations in terms of what can be done in the order. So the typical design that was used was plus or minus 3 hertz. During the time, 5 percent change in frequency was the maximum capability of the equipment. So we may have hardware limitations, such as, like OX equipment, fans, or whatnot for cooling may have some hardware limitations. We are still exploring that. But even on the software side requirements, like, having 5 hertz per second were not part of the design criteria back then, and it would require a significant change in software to achieve 5 hertz per second. It's not a simple parameter change that it could do or a simple software update. There's extensive design.

And especially for our older inverters, we have limitations in our control board that would prevent us from downloading new software onto it, or like with excessive new capabilities, so they would require hardware changes to even get some of these software fixes. So they would require a new control board, maybe a retrofit kit for some of these existing inverters and an entire development cycle dedicated to developing new firmware for a new control environment or a development environment, so that would take a significant amount of time and resources. It would probably be less expensive to just repower some of these older inverters with newer inverters.

For newer inverters, yes, they have wider capability to meet some of these wider frequency requirements. But we still -- not from OEM perspective, but from a power system perspective, we still don't see the need to have these wide requirements, especially given that none of the existing events or none of the existing studies have pointed to any evidence of wider frequency requirements.

MR. SHATTUCK: Thank you. We'll move on to our next question. Oh, Thomas, go ahead.

MR. SCHMIDT GRAU: Forty gigawatt.

MR. SHATTUCK: Forty gigawatts? Okay. Thank you. Yeah.

MR. COOK: Jamie, do we have these comments captured, the responses captured from all of the panelists in writing?

MS. CALDERON: Yes.

MR. SHATTUCK: We have someone recording, and then we also -- most of them submitted these comments in writing prior to this.

MS. CALDERON: Yeah. There was one or two, I think, we were waiting on, but --

MR. SHATTUCK: We got them, I think.

MR. COOK: Okay. Yeah, that's what I thought. I looked, and I didn't find them all. So if you haven't provided comments, written responses to these questions, please do so. There's a lot of complicated numbers and stuff going back and forth. We have a court reporter somewhere, but she may be -- are you getting all this?

COURT REPORTER: (Off mic comment.)

MR. COOK: God bless you.

(Laughter.)

MR. COOK: Okay. Thank you. Next question, Question Number 3: what documentation is necessary from manufacturers to -- I'm sorry -- to prove which hardware limitations exist that would prevent your equipment from meeting the criteria in Draft PRC-029, Attachments 1 and Attachment 2? Go ahead. Yeah.

MR. KARPIEL: There would have to be some kind of a declaration, obviously, from the manufacturer stating that you don't meet this requirement or that requirement due to this hardware limitation, this software limitation. We're not going to share our IP, obviously, but we do need to provide indication of what portion of the standard that it's not going to meet, why it's not going to meet that rather -- if that's -- this unit doesn't have enough buffer in that -- the buffer doesn't have enough energy to Ride-through zero volts for X seconds, this is why there's no space available to install a UPS or something of that nature. It's going to be basically our responsibility to put together a declaration, like I said, and with examples, curves, graphs pointing to certain specific hardware components that are not available for -- because they're not available on the market to provide back to the GOs and then back to the TOs.

MR. COOK: And how would you envision that being presented as like this -- here's all the model numbers, here's what they can and can't do, and issue that generically or based on requests from a specific generator owner?

MR. KARPIEL: We would probably do it on a specific request because the inverters themselves have different hardware configurations. We'd have to go look at that specific project's build to understand what is or is not included in that machine and what generation it is so that we can accurately provide detailed information regarding the equipment that's in that plant.

MR. COOK: Thank you. Just pass it over to your left.

MR. SCHMIDT GRAU: Oh, we echo that as well. I think for frequency, it has to be a declaration. There's a lot of things that cannot be studied in any study world on it, specifically of all the auxiliary equipment, and in the turbine there's also all the rotating part -- motors, your motors, et cetera.

For voltage evaluation at planned -- sorry -- point of interconnect, I think it's really important, again, come back to the OEMs are required to provide adequate models and also that the industry is allowing to use them because then you can do the proper evaluation. That's both for legacy and also future. We look at these graphs and they're very static on a PowerPoint, but the voltage will dynamically change based on your current injection profiles, your site-specific tuning, your nearby generation, so it's not enough just with the document. We also need to do the adequate design analysis for it.

MR. KOERBER: Just to add what was said, especially for wind turbines, these Ride-through capabilities are really complex system-level interactions. It's often not there's one voltage that goes above the one limit, that this one component limits. It's many auxiliaries, many systems that interact on Type 3 wind turbines, these interactions with the hardware side, the loading side, and it's not as simple as here's the one limit. And proving that something can't be done in a system that involves multiple software systems, it's actually really hard. Like, how can we as a manufacturer of equipment and then say, this can't be done, we don't know how to do it. That's a very hard thing for -- to attest to, right?

We will provide the capability of the turbine. This is what the turbine can do. Here's the testing. Here's the evidence that we have. But showing that something can't be done, it's a risk, but also it involves opening up our entire design process. What are our design limits? What are our margins? There's a lot of IP involved, and we don't see us being in a good position to provide documentation on capabilities, on limitations beyond what's the stated, published product-level capability. It's speculation, and it's a very unbounded problem. There's a lot of things you can do with modern software -- modern software systems if you had all the time and all of the funding in the world to solve this problem.

So declaring this can't be done, maybe for some small sub-problems, it can be done, but generally, we see significant challenges, not technical challenges, but just how we -- how we handle providing this documentation. What can we actually sign up to say this is impossible, and what happens if someone does it? What happens if we are wrong when we declared this can't be done?

MR. DAHAL: Yeah, I completely second that, and I would like to add that each turbine needs to be evaluated on its own. We will not be able to provide a -- forget about the fleet level, right? We have 20 models so far with various power-rated power output from them. So we won't be able to provide, let's say, 20 different statements saying our -- this fleet can do this. It has to be per turbine based, as has been indicated, seeing what is inside the turbine, what component was resourced, and what kind of documentation we ourselves have that can be used to provide you all with what you need. So that exercise, again, will be very timely. You know it will take time.

And also, I'd also like to highlight the fact that just because, let's say, converter can do it doesn't mean the turbine can do it. Again, I'd like to highlight that because every change in the parameter requires load and control analysis to see if tower can sustain if there is enough vibration, if there is enough harmonic generated. And all that study needs to be done for every change in parameter when it comes to frequency and voltage, and that exercise is very time consuming as well. And for legacy units, I mean, that won't be able -- we won't be able to do that either, you know. So there is a lot of nuance than just saying, oh, it's a simple software upgrade, then you'll be able to do it. That's not the case.

MR. COOK: Thank you.

MR. PATTABIRAMAN: Generally, I agree with most of what was said, would be able to provide some documentation on capabilities that are already published. But in terms of new capabilities, we would have to undergo investigation, and we would probably provide a document on our company letterhead signed by the appropriate officer on the capabilities of the equipment.

MR. SHATTUCK: Go ahead.

MR. KARPIEL: So a comment. The five of us up here are employed by highly successful OEMs. There has to be a consideration taken for those OEMs that haven't been so successful.

MR. SHATTUCK: Thank you, and I guess the next question bled into this one, but -- and we'll start from Thomas and come back down the line. But I guess a follow-on to that last question is -- and I think the answer is -- y'all touched on it, but, you know, what documentation are y'all comfortable with sharing, right, with someone like the -- a transmission planner or NERC or, you know, your utility or entity, because it sounds like there's a clash of IP and sharing information, right? But we also have to make sure that BPS is reliable, right? So there's got to be some maybe middle ground of IP and/or justification or something we can all be comfortable with on both sides, but I'm interested to hear what y'all are comfortable with and what that might look like. Yeah, Thomas.

MR. SCHMIDT GRAU: Yeah. I think a lot of it was said already on that part, but to reemphasize, I think all OEMs, at least I can speak investors here, we provide some kind of general description and specification that we stand within, and all third-party components we source has to comply with that. Some might be slightly better, some might not meet -- will just meet the specification on it, so I think that documentation is key to keep and also to trust. There might be declarations, like rate of change of frequency, that you cannot simulate, where you have to have some declaration, where we have to look at site measurement, where we have to do some attestations around that. I think that also aligns with some of the FERC orders.

And then I will go back to the modeling again. We see the recommendation for EMT models, detailed models. They will most likely or they have to live up to those specifications and then trust that and implement that in the study phase to get a more detailed instead of looking at paper, basically.

MR. KARPIEL: Yeah, I agree with you a hundred percent. Without an NDA in place, it's a fine line of what the OEMs are going to be willing to share publicly and openly, so, but we're going to have to find that line and provide enough information that a decision can be made.

MR. KOERBER: Yeah, very similar comments. We're generally comfortable sharing existing product capabilities. This also includes existing optional features that operators may or may not have used and implemented on their turbines. This is fully-designed capability, product specifications, comfortable sharing this. We also have very consistently provided, let's say, indicated fleet demographics as part of NOGRR245 for ERCOT. How many turbines are impacted by what curve? And we generally plan to do so to help you kind of run scenarios. What's the impact? What would happen if we do that, generally reasonably, and we plan to continue doing that.

We really ask for an understanding, is that we -- like, it's very hard for us to publicly commit on capabilities that haven't been developed yet. It's just not solid practice because we don't know what issues we will encounter. The only way of doing it is sharing IP, so that's where we see the biggest challenge is on kind of speculating for the future, informed speculation, but --

MR. DAHAL: I agree. I completely agree with that. Our customers should already have, like, whatever VRT set points, you know, FRT set points, all the curve, all the reactive power capability document, all the simultaneities that we call for (inaudible). You know, if the frequency varies more than one person, you will need to sacrifice active or reactive power or both. All those documentation, they should already have it, and we regularly provide that.

Like, when it comes to unit model validation like ERCOT requires for the new project, we provide the report to go with those as well. But any standard needs to adequately address what kind of test needs to be completed, in what manner, in what setting, with what margin, and what kind of report are they expecting at the end of the day. But it can't be open-ended and ask us to, you know, provide all the -- all the, you know, documentation when there is -- the requirement is so vague. And obviously we can't speculate on the future requirement. Nothing gets designed anticipating the future needs. You kind of touch bases whenever it's designed.

During the first year of the design is where we reach out to our customer and everybody and say tell me your requirement, right? And then after second year, that practice is closed, and we are solely focused on designing whatever the feedback we got. So you cannot retroactively, like, for the ROCOF of 5 hertz per second, even if we have the product right now, there is no way for us to go back for the product that we are currently entering the design phase to implement that. We are already too late on that. We need to keep that in mind as well.

MR. SHATTUCK: Thank you.

MR. PATTABIRAMAN: Very similar comments. The documentation we can share is often based on our judgment internally and what the capabilities of the inverter are. Even with an NDA, the information we share is often very limited because of IP issues. So yeah, that's essentially what we can share.

MR. SHATTUCK: Thank you. Before we go to the next question, maybe suggest that the other panels, we kind of hit on this topic and kind of understand the other side of what would -- what they would be comfortable with -- well, whoever they're representing would be comfortable with getting, and, like, you know, feelings on NDAs and all that kind of stuff and process. So, like, we heard you, all sides, and now maybe next panel we can hear from what we're comfortable with as evidence, and maybe we'll meet in the middle. We can go to the next question now.

MR. SCHMIDT GRAU: Sorry. Maybe quick comments on the evaluation. I think that's really key for this as well because we have seen a lot of this evaluation for it done in the past with PRC-024. People basically take our specification and plot the curves on top in Excel of the -- of the curve and say, oh, we're compliant or not compliant. That's so far from the truth, and I think that's also why we see some of these requirements, to some extent, go overboard on capability because we might not understand what is truly needed. And I think we as OEMs also have the obligation to help providing guide with that adequate information so we can understand the limitations of the equipment. And, yeah, it's a great step to talk about it today, but I think that's really important as part of the documentation is how to evaluate it, if you're compliant or not. If that's not specified and clear, understand that, we won't know what to provide.

MR. SHATTUCK: Thank you.

MR. COOK: Next question, Question 5, what is the generalized length of time associated with any design of current products to meet the criteria specified in PRC-029 without exception?

MR. KARPIEL: So we had one number here as five years. It could also last longer. I also think it's important to understand is it economical to redesign a complete turbine. If we have designed a turbine today and it'll be installed five to 10 years from now, if that platform gets completely obsoleted and we cannot sell it, where does the investment money come to redesign? So we're going to hit a race that we cannot comply with, that every time we have a new standard, we have to obsolete the old turbines. So it's really important for us that we also get some money back to keep investing and improve the products so we don't go into that race for it. So five years and maybe killing the platforms if the standards go in this direction.

MR. KARPIEL: So I've been in manufacturing a long time, and you have to understand that we're all lean manufacturers, not only from a manufacturing supply chain standpoint, but also a resource standpoint. We have a roadmap, and our resources are currently booked up for the next couple of years, if not more, going -- looking at next-generation products, operations, you know, the sustaining engineering that happens on the existing equipment, future generations, new designs. And then if we have to introduce something new, where does that go in the schedule? You've got design, you've got testing, you've got model validation and certification that has to happen, so minimum five to six years on a new design.

MR. KOERBER: And this is going to be a classical "it depends" answer, I think, for just new designs, turbines that are being designed, can they meet all these standards? Some of the numbers that have been mentioned here by my colleagues up here seem reasonable. That's about the right order of magnitude. We generally foresee the biggest challenge for products that are not no longer being manufactured, and when we internally evaluate it, what would a retrofit take? What does it take? We very quickly jumped to internal reasons. We no longer have a prototype. We no longer have a lab. Some of the simulation tools are no longer around.

But it's really not just the internal reasons. They are -- that's on us to overcome. It's a question of investment, and it's also external reasons. And on one hand, let's say, supplier relationships for products that we no longer manufacture, we may not be in business anymore with the suppliers of those subcomponents, which also have software, which have firmware, which we have to reactivate, which just like you are asking us the questions, what it takes, they will come back to us and say, hey, if there's no business, if you don't need to do a retrofit, we are not supplying to you actively anymore because we're not shipping those products anymore. It's just a whole supply chain that may have to get rebuilt up to even work through the engineering.

And then the second external kind of reason that makes this difficult is in our relationship with customers. We manufacture these turbines. We don't, in many cases, operate them. They've been operating 10, 15 years. Self-performing customers, they have their own services teams. They have -- may have retrofit those turbines. They may have replaced electronics. They may have replaced actuators. We don't know what state they're in, and they will ask us to guarantee that they meet the Ride-through performance if we do a -- if we do a retrofit. They will also want a warranty that whatever new software, whatever new component we install actually works and doesn't impact the rest of the turbine, as I mentioned, complex mechanical, electrical software system.

And then we won't -- we'll have trouble signing up for this without individually turbine-by-turbine, project-by-project, surveying and almost custom designing a solution for an asset that's been running for 15 years. All of this can be overcome, but that's why it's hard to give a timeline and talk about maybe the economics of what it takes to design a retrofit package for a product that no longer ships. And that's where the -- a lot of the uncertainty is coming from. Internal reasons, labs, all of this, it's one thing. It's the supplier and the customer relationships that come on top of it that make this fairly difficult and not very practical.

MR. DAHAL: I'd also like to highlight the fact that turbines today has not been like -- you know, we do not design a new product every five years, right? There've been accumulation of the experiences gathered throughout 15, 20 years, right, what worked in year one, what didn't work. We base the design on those components, like our experience, what failed on the field, what do we need to improve. So we are very excited to participate in IEEE 2800 and very static, you know, when it was approved.

Now, for OEM, it's, like, there's now one standard that we can design it for and maybe sustain it for relatively longer period of time without having to design to very specific market and have 10 different variation of the product. And now deviating from that just creates that, you know. We have to now face a decision: does it make sense for us to create a new product just to kill it in five years, and what does it mean by killing it? Then you are not getting any modeling support. If you have any issue on the field, good luck. I mean, we're -- like, that's what we are talking about, killing the platform. That's what it means. And looks like whole industry is kind of shifting toward like grid forming/grid following.

So I guess everybody needs to sit and think, like, what is the benefit that we're going to achieve? Like, is it worth it for OEM to force them to push back on getting, like, one percent of the capability more versus letting them invest on R&D to come up with new next generation of product, right? So that's also something to keep in mind.

MR. PATTABIRAMAN: So I agree with most of the answers said by other OEMs. In terms of timelines, if we start working on it right now, maybe it'll take three years to five years, design retrofit packages, design software in a completely new development environment, create all these packages for our customers. But the other important point is, you know, we also have a roadmap, what we are going to comply with in the next two, three years. And we see 2800 being significantly adopted, and our team is working on those requirements right now. We have a product pipeline. We have development resources assigned and whatnot.

So what I think these legacy requirements and retrofitting old equipment with new technology is going to do is kind of push out compliance for these newer sites coming in to maybe three further years down the line, you know, which is going to cause even more problems because there are more new resources coming online than there are legacy resources already out there. So not just does it delay existing products or, you know, not just does it delay implementation for legacy, but it also delays existing or new products under development.

MR. SHATTUCK: Thank you. We have one more question before we go to online questions, but I think most of it -- most of y'all have already touched on it briefly, so if you could maybe keep them to like 30-second answers, do rapid-fire summary of your already stated responses.

So the last question is, and we'll start with Thomas at the end, is, for currently in-design or, you know, future considerations -- or future considered products -- that's not good grammar -- are any of those able to meet PRC-029 criteria? So currently designed -- products that are currently in design or planned to be designed on your roadmaps, like we talked about, that would meet PRC-029.

MR. SCHMIDT GRAU: Yep. When I speak today and also talk about it, the PRC-029, I'm solely talking about the 4 hertz per six seconds. We are largely very, very supportive of the standard, but that specific requirement is depending on so many sub-manufacturers, redesign of the cells, different equipments, relays, that there is currently no product available with it. We can't retrofit any legacy turbines for it, and there is no product in design for future to meet plus/minus 4 hertz per six seconds.

So that is the limiting factor for Vestas. Again, just want to emphasize that we're greatly supportive of the PRC-029, but that specific requirement will require complete new platform. It will not go into our offshore market, it cannot go into the onshore market either, and there's no design for it.

MR. KARPIEL: Fortunate for us, there's no -- we're already meeting the requirements. All current and future products will as well. What I would like to say, as you can tell, that not all inverters and inverter stations are created equal, especially the legacy equipment that's out there.

MR. KOERBER: Generally, all our new product designs are aligned with 2800, so we're evaluating what it takes. As I've mentioned, several of us, including me, several times, the big concern is around the legacy fleet, not new units. Generally, design power generation equipment, meeting grid codes is a key part of it. There's some specific technical requirements in PRC-029. Some of them were mentioned. Some of them were mentioned in our comments. The one we haven't talked a lot about here that we do see as requiring a bit of a realignment on our side would be multiple fault Ride-through, going from two events to four events in 029, in general aligned to 2800, evaluating what it would take to realign. The stronger concern and most of the comments are really around the legacy fleet, not new developments.

MR. DAHAL: I completely agree. Our newer products will comply with 2800, but we do not have -- we haven't considered this 64-hertz-per-6-second criteria in any of our currently-being-designed product, so not the new one. We haven't considered that, and I don't think just a -- preliminary analysis doesn't allow us to be able to meet it just because of all the auxiliary motors that are in the turbines. And, you know, we are not going to get any assurance from our vendor that their motor would be able to Ride-through those. So we don't -- we have no product.

MR. SHATTUCK: Thank you. Dinish?

MR. PATTABIRAMAN: So for products in development in the future, we'll be able to meet 2800. That's in our planned roadmap, but there are at least a few constraints with PRC-029, which limit us from meeting it. Some of these were mentioned before. You know, one of the examples is one-cycle filtering for instantaneous overvoltages, which we won't be able to meet. I heard somebody mention that, oh, greater than 1.8 per unit, you know, there's not overvoltage going to occur on the grid side, but things could happen internal to the plant, which could trigger that kind of overvoltage. There could be a resonance condition. There could be a failure of one of the components that could cause a severe overvoltage. There are extensive studies done, called temporary overvoltage studies, to determine how much energy a surge arrestor can handle and so on. So the various constraints would limit us from, you know, achieving this one-cycle filtering for instantaneous overvoltages, including inverter protection, inverter components, OX components within the inverter.

The other constraint I see being a challenge is the 25-degree phase-jump requirement. The 25-degree phase-jump requirement is also there in 2800, but there is additional wording added here in the PRC-029 language, which states 25-degree phase jump initiated by a non-fault event, this is allowed to trip. No other kind of phase jump is allowed to trip, which is something -- which is the first from 2800. Also, it creates complications because the exception only states for phase jumps created by a non-fault event. A lot of fault events are actually going to create phase jumps, you know. The inverters really cannot distinguish between non-fault-initiated or fault-initiated phase jumps.

Significant phase jumps. So essentially, the language states that if there is a fault event causing a significant phase jump, like a 90-degree phase jump, the plant is supposed to Ride-through. But that is something that we cannot really ensure, you know, the significant phase jump is going to instantaneously cause the current to jump significantly high and trip the plant. So these are the differences -- the key differences between 2800 and PRC-029, which pose challenges. That's why I mentioned earlier and why the differences between 2800 and PRC-029 when 2800 has been discussed extensively, approved widely by a lot of people, and there's also test procedures coming in with 2800.2.

MR. SHATTUCK: Thank you. I think at this time we have 10 minutes for Slido questions or questions from the room. We'll let Howard go first. You've already asked a couple, so Howard, you go ahead.

MR. GUGEL: Thanks. Howard Gugel, NERC. So I've heard a comment a couple of times today that is a parity issue for me because it's different from what I've heard in the past. So I'm hearing that you as OEMs have accurate models that you've tried to provide to the ISOs and utilities, and they refuse to allow those models to be used. When we talk to ISOs and utilities, they say we can't get accurate models because the OEMs refuse to provide them because it's IP. I don't -- what's the right answer because that's -- we're hearing it from both sides and I don't -- I can't figure it out.

MR. SCHMIDT GRAU: We have the models, and we provide them to anyone that requested. So we are, at least from Vesta's perspective, talking with different ISOs. We are reaching out to them proactively saying, can we provide you updated, accurate models? We see very big interconnect projects in in U.S. coming on board, and it's our bread and butter to sell turbines.

If we have any incident in the grid, it's going to cause a political storm first, so we need to make sure that the equipment we sell is reliable operating, on the grid, and the best tool we have is for the models. So we are really emphasizing utilities to ask and accept the equipment-specific models, and we also are trying proactively to ask what requirements do you have for usability of our models and tools. There's technology out there that can streamline. SGRET B4 is one thing that can be used for EMT/RMS that will significantly improve for utilities.

So we need a mechanism to allow to use the adequate information, and we need ISOs/TSOs to be more upfront with the usability requirements for our models and validation requirements for it. So that's an accountability we have to take on as an OEM, but again, that it's -- we can't afford any reliability issues either, yeah. So for sure, I speak for Vestas here, of course, not for all OEMs. Any concerns, if you heard anything else, please reach out, and we can definitely deep dive into that.

MR. MAJUMDER: Hey, Alex, if I may, just as a GO, who has opportunity to work with all of them who are on the podium. To answer your question, Howard, it's easy. Please go ahead and look at the generation interconnection requirement from each of those ISOs. It's documented. They clearly state we will not accept any user-defined model, so you don't have to get your answer based on speculation. It's there, documented. They don't allow it.

I have had my fair share with working with all of the ISOs where they would want accurate model, and they are absolutely refusing to work with a user-defined model. And then the question we get, so are you saying your generic model is inaccurate? That puts us in a very difficult position because we cannot say that we have given an inaccurate model, which is not true, but it's what it is.

MR. KARPIEL: It's generic, generic by nature.

MR. RODRIGUEZ: This is Fabio Rodriguez. I'm a transmission planner for Duke Energy Florida, and a concern about the models, it's very simple. When we do a system impact study, the OEM sends a model. We do the study. We determine what the impact on the system is, and there we go. Then if there is a new model in our interconnection requirements by FAT 002, there is a requirement that if there is a modified change, the model has to be restarted to see what the new system -- new impacts are on the system, and that's the -- that's the process.

So when you guys come up with a new firmware or a new software upgrade, or, you know, different settings, if there is a modified change, which every utility should have in their interconnection requirements, you know, one of the modified changes, it's a new model. One of the modified changes is, you know, more than five percent in this setting. So if you have that change, the TO, or me as a transmission planner, I cannot accept your model until I do a new study to determine if there is any new impact on the system by those changes, and that's the process that we have. It's a process that should work.

So you know, new models are working for any TO. The thing is that they have to be restarted if there is a modified change determined by the utility, by the TO, and they have for -- you know, due to -- I mean, in FAT 002, every TO, every utility has to expel what the requirements are or what the -- what they call modified change to trigger the restudy.

MR. SHATTUCK: Thank you. I think maybe we'll get back to frequency real quick.

MR. COOK: Yeah.

MR. SHATTUCK: The modeling piece, just keep in mind, we have -- NERC has published modeling guidance that says if you want accuracy in your studies, use a user-defined model simply. They're in -- they're on the website. They're posted. Just Google "NERC dynamic modeling guidance," and you'll get what we recommend as NERC, and you can read that and adopt them if you want to, adopt the recommendation. So frequency question.

MS. CASUSCELLI: Okay. I'm going to interject with a question from the --

MR. SHATTUCK: Yes. Thank you.

MS. CASUSCELLI: -- from online here. So in order to assess all of the Ride-through defined in the standard, do the OEMs agree that a plant-level EMT study is needed to confirm Ride-through?

MR. DAHAL: Absolutely.

MR. KARPIEL: Always a plant -- it's always a plant-level model.

MR. SCHMIDT GRAU: Yes, EMT plant-level models.

MR. DAHAL: Yes.

MR. SHATTUCK: So yesses all around? All right. That was easy. No questions like that before that.

MR. MAJUMDER: Again, Rajat from Invenergy. Before I ask my question, first of all, I would like to thank Alex for a very insightful presentation that he did before lunch. That's precisely what I was referring since from the beginning, and my apology for being the broken record.

So based on Alex's very quantitative presentation, we have seen expanding plus/minus 4 hertz per six seconds has not been established as a sufficient risk. It's clear. We have just heard about all the manufacturers, and especially to Scott's point, that there are probably little less successful manufacturers who are not even around the table. The technology is not there, and they do not see the reason, as of now, because there is no basis of expansion of that.

So my question to the Standard Drafting Team and the leadership is, so far no incident that can be pointed has happened because of that expansion. So if the standard goes ahead with this, we are essentially going to go ahead, make all of those plant noncompliant and open the breaker. How is that helping with our bulk electric system reliability, which has not been the reason of any reliability risk. Again, I'm zeroing in in that frequency Ride-through.

MR. SHATTUCK: Thank you.

MR. AL-HADIDI: Thank you very much. Husam from Manitoba Hydro. So maybe I have few questions based off my involvement in the standard itself. I know I take these standard looking at low frequency 57 hertz for almost five minutes. You guys okay with that, it's not an issue, so you go only 56.1 hertz per six second become an issue or how that really change, because really it's a fluxing issue. It's a time-related issue. So if you can understand five minutes, then what's the difficulties on that for a low frequency? Then I'll go about our frequency, which is normal auxiliaries even for today's surplus machine where, under load rejection, the frequency goes to 70, 80, whatever the case.

So it's not -- it's not abnormal for short time, even for current existing synchronous machine, which deal with the same auxiliary to some level, which is the cooling and all that, which can stand for a large frequency deviation for a soft-load rejection. We just open the breaker. What's the difference? Why you guys think it's an -- a big concern? What I think it's -- if it's a big concern, we need to consider it, but I just want to understand why this concern become significant, where it's not really that much of a change, at least from where we are right now.

MR. SCHMIDT GRAU: I can maybe start. It's the --

all the auxiliary equipment in the turbine is not designed or certified for it, for those values. So as mentioned earlier, also, we manufacturers have to rely on manufacturers, and there's no certification, there's no standard for any equipment we can go out and purchase to put into our machines today that will comply with that. So it will require industrial chains across a ton of equipment. We are not talking inverters here only. We are talking everything. You will have equipment in your substation that is not designed to Ride-through, so you might have your substation tripping offline before the turbines. You might have loads nearby that will go offline as well. So the requirements exceeding, to my knowledge, all industrial practices and other design standards.

MR. AL-HADIDI: Yeah, but it's already existing. As I said today, load rejection on any generator, it create very large overfrequency or very large under frequency, depend, but it's already -- the document is already there which can Ride-through it, so it's not something which is not manufactured before. I see the standard as saying continuous operation or just integrated operation for certain number, but doesn't prevent it from running. And voltage per hertz is already like exception criteria in the standard. So is it voltage per hertz? Is it what the limitation of the equipment --

MR. SCHMIDT GRAU: We are talking frequency plus/minus 4 hertz per six seconds --

MR. AL-HADIDI: Okay.

MR. SCHMIDT GRAU: -- that there is no standard to, what I at least know, that is designing any equipment or certifying to that.

MR. AL-HADIDI: Okay. So it does mean it's only that 57 is okay, and for other frequency up to 62 hertz, that's what you guys guarantee, or is this really the -- where we are right now, we need to move to that direction?

MR. SCHMIDT GRAU: Ask if it -- we had to do R&D?

MR. AL-HADIDI: Yeah. Is it R&D?

MR. SCHMIDT GRAU: It's not R&D. It's about we are not able to source equipment that is designed or certified to that for the auxiliary systems.

MR. AL-HADIDI: Okay.

MR. SCHMIDT GRAU: Today.

MR. AL-HADIDI: Does that mean that whenever you guys now are manufacturing, the protection setting is set on the border of this curve and you say --

MR. SCHMIDT GRAU: Yes.

MR. AL-HADIDI: So that's --

MR. SCHMIDT GRAU: We have pretty much maximized out, and also to be able to -- there's always margin, but it's -- we have certification for that equipment. I'll let others maybe also reply, but we are maxed out, at least for the Vestas equipment, where we are with our specification today, and we have done the research. Even with long extension here on the equipment, we can't get signoff from any supplier with any of our auxiliary in the frequency.

MR. KARPIEL: So I don't really consider it margin. I consider it a safe operating limit, and then we've already pushed those limits. I'm sure -- I believe we're all saying the same thing, that we're already pushing those operational limits where we feel safe for our equipment.

MR. AL-HADIDI: Okay. What about ROCOF? Is 5 hertz per second something you -- is it something feasible to do, or it's -- where we are in that 5 hertz per second for legacy or for future design?

MR. SCHMIDT GRAU: Vesta's turbines, Type 3 and Type 4, all do 5 hertz per second, yeah. Vesta's Type 3 and 4, it's public. You can go in. They comply with the NOGRR245 of August last year.

MR. DAHAL: For SDRE, that's true only for new units. We do not provide -- we do not have any proof from our legacy turbines that we can go and do 5 hertz per second. That is only applicable for new ones, not the one that has already been installed.

MR. PATTABIRAMAN: Our legacy equipment, there was no requirement for rate of change of frequency at the time these inverters were sold or commissioned. The standard at the time, I think, UL defined maybe 1 hertz per second as a requirement for some of these inverters. And so most of our legacy inverters are tested at 1 hertz per second and safe to operate in 1 hertz per second without tripping. Like I said earlier, changing the software, it's not a simple parameter where you can go and update 1 hertz per 5 hertz per second. Software has to be changed extensively, and our legacy products don't support that. We would have to change hardware to even change software in some of the legacy inverters.

MR. AL-HADIDI: Maybe I'll go to the second -- to the question about transient overvoltage.

MR. SCHMIDT GRAU: So I'll just add a comment on the ROCOF first --

MR. AL-HADIDI: Sure.

MR. SCHMIDT GRAU: -- which I think is important. Avesta's turbine don't have ROCOF protection. It's the equipment, again, that is potentially not able to Ride-through, so I think that's also really important to understand when we evaluate these. I do see ISOs run very detailed, accurate EMT studies for ROCOF. They can do a million hertz per second. The PRC CAP model will never trip because ROCOF is not a protection setting in the turbine. So there is, again, a lot of auxiliary equipment and stuff that is not certified or designed for these things. This is just one example. It's really important to understand that it's just not only inverters. We have a lot of rotating masses, sensors, a lot of things in turbines.

MR. COOK: Folks, we have about two more minutes left, so we'll take one more question.

MR. AL-HADIDI: Yeah. Just quick question about transient overvoltage. They may help us with this question about transient overvoltage. You guys see one second/one-cycle filter, it's difficult to achieve and may create some damaging issue.

MR. PATTABIRAMAN: It's not possible in our inverters.

MR. AL-HADIDI: Well, and understanding that the standard is saying that if you need to protect yourself from damage, you could trip, so it's really -- it still is there to cover for that. But the question now, what's your guys' recommendation how to address it in the standard to ensure that transient overvoltage for just a spike, it's not really a noise or anything in the measurement which cause the unit to trip, how we should deal with it in the standard in better way.

MR. PATTABIRAMAN: There are two ways. I think one is already the NERC recommendation, which is maximize settings to the extent possible, limit instantaneous -- add additional filtering to instantaneous protection internally, and the other path is to kind of adopt 2800.

MR. AL-HADIDI: Okay. Thank you.

MR. COOK: We'll take one more from the gentleman that's behind you.

MR. HAKE: Thank you. Appreciate that. I'll be quick. This is Sam Hake with AS Clean Energy again. So we heard a lot this afternoon about the challenges in evaluating what we cannot do, obviously relating to equipment limitations. One point or a question that I wanted to ask is if you guys see similar limitations also applying to the concept of maximizing inverter performance. We also hear a lot about that, and in our experience, we've run into a lot of issues when we open these questions about how can we maximize performance. We get similar feedback as to what we've heard about what we cannot do and are we limited. So just curious if anybody has comments on that.

MR. KOERBER: Yeah. It's a -- it's a similar concept and some of the -- some of the challenges are similar. Maximize, where's the limit of maximize?

Does it mean you have to invest 10 years of R&D into maximizing it? Generally, maximizations are often understood as make sure the settings are right, make sure all already-available optional features are applied. We actually maximize to the capability stated by the OEM. I think that's fairly straightforward, in my own opinion. And where we run into the same challenges that I was talking about earlier is when we are asking us as OEMs to essentially invent something new that gets more capability out of the already-installed hardware. And parameters can change, software can change, but what happens if a sub-supplier firmware needs to change, or in order to update firmware, you need a better processor? Then it quickly spirals. But I would say structurally similar. It's really do we go beyond stated capability, including all already-designed options? Yeah.

MR. COOK: Yeah. I don't know if you want to add to that.

MR. SCHMIDT GRAU: I want to echo it.

MS. CASUSCELLI: All right. We'll do one last question here if that's okay, Todd. Thanks. There's a question remotely here that asks if any of the panelists work with AEMO and provide source code for their models to the AEMO planners and operators and can speak to that.

MR. SCHMIDT GRAU: I can speak to that. I think AEMO is a very, very good example of the modeling challenges we are facing here in U.S. providing source code. We simplified that source code significantly. That caused a lot of issues with PSSE studies, showing a lot of false positives, which we also see here in U.S. with the generic and standard library models. AEMO is now moving towards full EMT real-time simulation, probably obsoleting RMS, and I think that's going overboard. And to the point earlier, we are a lot of mature manufacturers here. If we go down that route and we start forcing EMT and so strict requirements, in my opinion, it will not kill, but it will slow down innovation, new players, competition in the market significantly. And that's -- I don't think it's healthy for innovation or for the industry as a whole.

MR. KOERBER: Yeah. I assume AEMO -- Australia

Energy Market Operator, or is that another AEMO? I interpret this question as being about Australia, one of the most strict grid codes in the world, requires a lot of transparency, is a significant challenge, but it's also very structured. And our experience working with AEMO is they've also been very open in kind of walking the process with us on what's needed. They've been -- they've had several requirements. I commented on MFRT, multiple fault Ride-through, where Australia has probably the strictest requirements in the world, but they're also very open, very technical in working through some of those challenges with the industry.

Real code, actual source code, actual product-level code is a challenge so far providing this in compiled form where the code -- the source code is not visible, but the performance actually 100 percent matches. The product has been a way to go, implementation challenges. There's many layers when it comes to working with AEMO. I don't think that's a discussion for here, but yeah, we, we work with them extensively, and it's been a journey.

MR. DAHAL: It's not related to that question, but

I do like to bring something to attention as well when we're talking about the model AEMO and all. You know, I think Rajat mentioned, like, most of ISO requires generic model. And what we are seeing from OEM side is people are getting so familiar and comfortable with generic model, that they are changing the model significantly when they're submitting, you know, the model of their plan to ISOs and RTOs. That we know nothing about, right? There is a lack of manpower that I don't think anybody has talked about because not a lot of developers are capable of running the study -- plant-level study on their own, so they have to outsource that study to somebody. And the market is in such a way that there is a, you know, severe lack of, I'd say, knowledgeable people to run the study.

So that model that gets submitted by the OEM to the customer might not be the same model that gets submitted by the customer to the TSO/RTOs as well, so that is also something to keep in mind. Everybody's talking about, oh, OEMs are hiding their control block, we need access to control blocks, we need access to -- we need access to that parameter and that parameter, while forgetting the fact that, you know, if you were to use the OEM/UDM model, you'll get a very accurate representation. And if you have to make changes, then you have to come to us. Then we will tell you what is possible and what is not with generic model.

Then people get very comfortable using those and not realize that changing parameter might drastically change the behavior of the turbine. And, like, recently, a lot of inquiry that comes to us is after the fact that, oh, your model is not -- your IRMS model is not behaving like EMT model, and when you look through it, it's been completely altered, and that's also the challenge that needs to be addressed. And hold the timeline, six-month applicability, one-month applicability, knowing that plant-level study has to be done and is this feasible amount of time to achieve that, that's also -- that also needs to be considered.

MR. SHATTUCK: Thanks, and I think we're out of time, but let's just maybe do one "yes" or "no" at the end. So this last situation was just described, you know, getting a model back that was changed. You have no idea what's in there. We'll go "yes" or "no" from

Thomas down. Have you experienced that?

MR. SCHMIDT GRAU: Yes, pretty much all sites.

MR. KARPIEL: Yes.

MR. KOERBER: Sorry. Could you -- can you just restate the question, please?

MR. SHATTUCK: So the situation that was described where, you know, you've given a model out and then you get it back later from generator owner, utility, or whomever, and it's different, and you had no idea.

MR. KOERBER: I've not personally experienced this, but maybe I'm at a different part of the organization, so I can't comment on that.

MR. SHATTUCK: Okay. Thank you.

MR. KOERBER: I assume yes, but I can't confirm.

MR. SHATTUCK: Finish? You already answered.

MR. PATTABIRAMAN: Yeah, I already --

MR. SHATTUCK: Yeah.

MR. DAHAL: Yeah, absolutely. In fact, we have provided RECA models, and we have received REECC back for some reason.

(Laughter.)

MR. SHATTUCK: All right, good. I think we're done then.

MR. BENNETT: All right. Well, thank you for our well-informed panelists. I think that was very technical. That was very informative. I think that achieved what we were hoping it would achieve today. So I don't know, just them a round of applause. We appreciate you.

(Applause.)

MR. BENNETT: So with that, I just want to let everybody know there are a number of questions online. We're collating those. We'll get those to the panelists and see if we can get some answers later today. But with that, let's take a 15-minute break, and we'll come back with our last panel of the day to talk about some challenges with the current criteria for PRC-029. Thank you.

(Break.)

MR. BENNETT: Okay. So it looks like we're getting everybody together back in the room here. We've got our panelists seated and ready. It looks like Charlie's smiling at me. So with that, I guess let's introduce our last panel of the day.

So we're going to talk about Addressing the Challenges of Voltage and Frequency Ride-Through Criteria. So to lead us through that is once, again, Charlie Cook from Duke Energy, as well as Howard Gugel from NERC. So take it away.

MR. GUGEL: Excellent. I guess before we start, if we could just have everybody just briefly introduce who they are and who they work for.

Manish Patel, EPRI.

Andy Hoke, National Renewable Energy Lab.

MR. CHWIALKOWSKI: Todd Chwialkowski, EDF Renewables.

MR. LAUBY: Mark Lauby, NERC.

MR. GUGEL: A man who needs no introduction.

MR. COOK: Yeah. Once again, I'm Charlie Cook, and I work for Duke Energy, representing the Standards Committee. Thought of a funny, though. I had this mic on when I walked into the bathroom.

(Laughter.)

MR. COOK: But then I realized, hey, John Belushi did a similar skit on "Saturday Night Live," so I turned it off, so.

MR. GOGGIN: Michael Goggin with Grid Strategies.

MR. GUGEL: I always think of Lesley Nielson and "The Naked Gun" when he did that same thing, too.

MR. COOK: I'd probably do that, too, yeah.

MR. GUGEL: I'm afraid of that. I'm Howard Gugel with NERC, and thank you all for participating on this. I promise I won't ask any questions about models during this -- during this panel. But do want to continue the conversation that we had earlier talking about voltage and frequency Ride-through, and the first question that I'll have is specifically, Mark, from NERC's perspective. And that would be, you know, have we identified -- has NERC identified any challenges about understanding and evaluating the impact of generators failing to meet either PRC-029 or IEEE 2800?

MR. LAUBY: Models, no.

(Laughter.)

MR. LAUBY: One of the -- I think one of the challenges is it reminds me of when I used to work in, in Asia, and they'd come to me and say, well, how much coffee do you want, and I'd say, how much did you make. We're almost in that situation now where we're saying to folks, well, you know, please give me this amount of frequency or voltage, and they say, well, how much do you need, and we can't answer the question, even 2800, of course, which is a global standard, right? It's kind of a -- I'll call it a global foundation, but we haven't done the hard work. And what I mean by "the hard work" is, you know, doing the system analysis to understand what are the frequency response that we need. How do we know that what we're putting in the standard is going to ensure that we have sufficient amount of Ride-through, be it voltage or frequency?

Now, we have some data, you know, some -- and we had -- you know, that's on some of the -- some of the events that Alex went through, which was helpful, though, of course, we did have substantial amount of spinning machines out there to help us with the frequency when there was a need for frequency, or operators that were taking action, like shedding load to make sure the balance is kept.

So I think that's one of the hard parts is having the data and the models and the simulations. We got to get beyond the inverter-based resource and what it can do to getting to what do we need, and then how will -- how will we drive the -- a standard to get there, so what's a good starting point? Well, you know, I'll leave it to the Drafting Team and the people -- and the folks here, but, you know, clearly we're -- it's kind of like a golf site, the old flat start. We're going to start someplace, and then over time, we'll find out as this evolves, if we need more or less.

There are places -- I talked to Jason -- not there yet -- 2800 would actually cause you problems, voltage collapse problems if you -- if everybody finally went 2800. So you got to do this hard work to say, hey, in some places I'm going to have to have less than 2800, and that's okay, it's easy to do that, and some places you're going to need more depending on where you're at, but then that's okay, too. You can do more than the standard, and less, just make sure you have the technical reasons for doing that. So it's not easy, and you need good models and good simulation tools.

MR. GUGEL: Yeah. So to -- so to kind of build on that because now we -- I think we kind of see the issue, maybe we could talk about the magnitude of the problem here. So from the rest of the panelists, from your perspective, you know, what percentage of the existing portfolios would be affected by the draft PRC-029 criteria, and how would that change? Would there be less or more affected if you changed that criteria to meet 2800?

MR. GOGGIN: I can start. So the numbers I've seen, and, you know, we heard on the previous panel from folks on the wind and solar side it's a significant share of the fleet. The numbers I've seen from developers who will be speaking today and tomorrow, 20 to 50 percent of their fleets, and, you know, again, this is out of a base of several hundred gigawatts. And this is -- I should clarify. I'm talking about the frequency Ride-through requirements in PRC-029.

So, you know, 20 to 50 percent of several hundred gigawatts is a hundred-plus gigawatts of existing resources that have major challenges with this, would either require extensive retrofits or complete retirement and replacement of the resources. And, you know, we've heard a lot about the wind, but, you know, anecdotally, we've seen with solar and batteries, I think it's an issue of just, you know, these -- all these plants were designed before the standard was thought of. And so it's very difficult with a few months' notice to go out and find out what the capability of the plant is and, you know, how perform -- just trying to meet this.

And so we really don't know, and, you know, I'll come back to, so what is the solution? This is why we don't do retroactive standards. It's really hard to get them right and make sure that they work for existing resources. There's a long history of doing only prospective standards at FERC and NERC, and it's for a good reason, and on the frequency side, we need that. It has to be on the table. Otherwise, this just doesn't work. And I think going forward, IEEE 2800 is what the industry is designing towards. And, you know, if you make that effective, you know, as of the, you know, basically, when the standard takes effect all interconnection agreements signed after that date have to meet that. I think that works for the industry on a going-forward basis.

Existing plants, again, weren't designed for 2800, and so, you know, we need this -- it needs to be a prospective standard only on the frequency side. And, you know, just given the magnitude of what's at risk here, a hundred gigawatts taken offline potentially permanently or at least for extensive retrofits, is a major reliability risk. We're doing way more harm than any good we're doing if that's -- if that's going to be the result, so this has to be fixed. So an exemption for existing IEEE 2800 for going forward.

MR. CHWIALKOWSKI: I'll go next. EDF, again, EDF renewables, a developer, and I'll go down the path of we've had an opportunity already to do some of our analysis with ERCOT. Now, ERCOT jumped ahead of NERC, and they went forward with their Nodal Operating Guide 245, and they're looking at, at this point, forcing us to maximize -- at least analyze the maximization of our sites within the ERCOT region.

So we've had a chance to work very closely with the OEMs and try to figure out where do we stand with our current fleet. And I have some numbers for you and I don't mind sharing them, but I'll also ask the other developers in the room please share that information. I know some of you have some numbers, and we aren't the biggest developer out there, but our numbers are also pretty significant. So for us, looking at the new PRC-029, similarly, as we looked at NOGRR245 and IEEE 2800, we're looking at almost 40 percent of our fleet being affected by this and affected in multiple ways, not just frequency alone, not just voltage alone. But when you look at our older fleet, our older turbines in the ground, it's both the voltage and the frequency Ride-through that's an issue.

And then looking specifically at ROCOF, looking at the phase-angle jump, looking at multiple excursions, from the OEMs, we're getting the kind of information that says until we test this, I cannot give you a definitive answer. Well, as a developer, I want a definitive answer, right? I want to know how do I respond to the regulator, but I can't get that. And you just heard the previous panel saying that's very tough to come about. How do we test that? The OEMs are my source of truth. If I can't get that information from them, where do I go? What am I supposed to do as a developer or as a generator to get that information to answer the regulator?

MR. HOKE: So, you know, I'm not a generator owner or an OEM. I'm a -- I'm a researcher. So I would basically let everybody just listen to what we've heard from the previous panel, what we've heard from these guys up here. It's a pretty significant percentage of the legacy fleet. I'd also comment, I think this has been brought up before, that when we wrote 2800, IT wasn't designed to be retroactive, and so applying it retroactively causes all the problems we've heard about. Now, and I also understand why people want to apply it retroactively, right? We have a big uncertainty in what does the grid need. We're installing solar and wind plants. They're going to be on the grid for 20 years or more, and we don't know what the grid's going to need in that period. And so there's this desire to be a little bit conservative and get as much Ride-through as we can because we might need it.

But I think what Mark said at the beginning, let's get something that -- what we can get from industry right now without slowing down the deployment of these plants and without causing, you know, PEP companies to go out of business and get what we can now. And in the meantime, researchers like us will try to figure out what the grid is really going to need and have a better idea of that, and maybe we need to revise it and come back to this in the future. So get the low-hanging fruit now, get a good Ride-through standard now that everyone can be on board with, and then if we need to revise it in the future, we can revise it.

MR. PATEL: So I have nothing else left to say really, but I'm looking at some of the notes my wife is sending me right now.

(Laughter.)

MR. PATEL: Just like how my weekends go before I open my mouth in front of family and friends, you know. So I think Andy mentioned this. When we wrote 2800, it was a forward-looking standard, and some of the requirements in there does not exist today in any NERC standards, right? Phase-angle jump never existed in a NERC standard. ROCOF never existed in a NERC standard. PRC-024, for that matter, is not a Ride-through standard. It is voltage and frequency trip-setting standard.

So when we wrote 2800, we had this question: what does grid need and what can IBRs do? And we don't have definitive answer on either of these questions. We tried to find a middle ground somewhere based on engineering judgment, right, a lot of head scratches, and talking to a lot of OEMs about can equipment really do this or not do this. And even then at the time, I remember a very difficult conversation with couple of OEMs on something very specific in the standard, and few OEMs said, Manish, for us to answer this question with any confidence, we have to be able to test our equipment first, and we have never tested our equipment, so we cannot affirmatively say that we can or cannot meet certain requirements, right?

So anyhow, we wrote lot of 2800 requirements thinking about future grid. A lot of folks were involved, 400-plus, and they all agreed to some of those requirements. As far as how many GOs or portfolio will be affected by either PRC-029 or IEEE 2800, you heard OEMs. I think a couple of numbers stuck to my head was one OEM said 40-gigawatt capacity. Another one said 50 to 60,000 units, right? Fifty to 60,000 units. So that's just few examples.

I work -- all my career I've worked on transmission side of the business, so I don't know the numbers. But forward-looking standard, applying it to the equipment that was placed in service five, 10, 15 years ago, and not having that same equipment in a lab anymore to test it for future new requirements is a challenge.

MR. GUGEL: So, and maybe we'll start at the far end and work our way back for this next question. So, and this may be a difficult one to answer, and if you don't have the answer for it, I think that's fine, too. But what would -- what do you think would be the limitations that would need to be fixed, if you will, or changed in order to meet the voltage -- we'll just talk about the voltage criteria -- the voltage criteria that's spelled out in proposed PRC-029? Is there -- what hardware do you think would need to be worked on for that, if you will, or what are some reasonable solutions that we could come to, to maybe not even to necessarily meet that, but to come close to what's shown in PRC-029?

MR. PATEL: Yeah. I'm sorry if I say something wrong. My friends who are OEMs don't come talk to me at the bar. But I think -- I think again, voltage Ride-through requirements were forward-looking requirements. I think at the end of day, it came down to when we were writing 2800 -- and then PRC-029 voltage Ride-through almost mimics the IEEE 2800 voltage Ride-through. At the end of day, it came down to a lot of auxiliary equipment, all this wind turbines and, in some cases, BES and solar inverters and then VSC HVDC, right? The IBR definition includes offshore wind plants that it -- that connect to AC transmission system via VSC HVDC converters.

So all these are very different technologies, and limitations for one technology might not be the same limitation for another technology, but it seems like at the end of day, a lot of these things came down to a lot of auxiliary equipment that is designed on some other industry standards -- IEC NEMA curves, all that kind of stuff that is sourced by OEMs of wind turbine generators, solar PV BES, and VSC HVDC to go along with their equipment. So it comes down to a lot of auxiliary equipments.

MR. HOKE: Not a whole lot more to say there because, I mean, it's sort of summarized pretty well what we've heard from the OEMs in the previous panel. You know, it's equipment specific. Sometimes it might be auxiliary. Sometimes might be that you need some power for the controls at low voltage for a certain amount of time, but -- and sometimes maybe it's a software change. But as we heard, even with those software changes, you have to go back and retest that, so it's not just a matter of updating new firmware. I'm basically just summarizing what we've already heard, so I'll leave it there.

MR. GUGEL: Well, maybe I can take us in a little bit different direction then because there's a question that I've had. If we made a switch, it seems like the vast majority of inverters that are at least on the legacy equipment and may be specified for now, tend to be more grid following. If you made a switch to take those inverters to grid forming, would that maybe solve some of the issues that we're talking about for voltage and frequency Ride-through?

MR. HOKE: All right. I'll jump in if no one else wants that one.

(Laughter.)

MR. HOKE: I think you're going to run into a lot of the same issues, and maybe even more issues because now you're not just doing Ride-through, you're also doing a whole different type of low-level control for the inverter. I know that some of the inverters that are out there can be retrofitted to become grid forming. Others need a new inverter to become grid forming. Again, it's a commit-specific question. And the Ride-through issues, that doesn't make the Ride-through issues go away. The Ride-through issues are still there. You still need the auxiliaries to work. You still need the control power to be there. So I don't think it necessarily solves that issue. It's another super important issue to talk about, but I don't know if it necessarily helps with the Ride-through.

MR. GUGEL: Good. That's a question that folks have asked me in the past. And, you know, I didn't stay at a Holiday Inn Express recently, so I didn't have a good answer for it, but I thought maybe some of the smarter heads here might have a good one for that.

MR. PATEL: I think that question may have some value in terms of what does grid need. Does grid following gives what grid needs versus what grid forming, but I don't think you can compare grid following Ride-through versus grid forming Ride-through, and challenges, and all that kind of stuff. I think that question may have value when we talk about grid needs.

MR. GUGEL: Yeah. Just the question that had come up for me was, does the fact that maybe it's less dependent upon the frequency that's provided by the system allow for some different controls that might make the ability to Ride-through different as opposed to looking at the frequency on the system and reacting to that internally into the inverter.

MR. PATEL: So I think repeating myself and repeating with everyone else on the previous panel, I think a lot of this limitations is not only the wind turbine or the -- or the inverter. It's a lot of auxiliary equipment, right? Grid forming won't change in the auxiliary equipment. It remains same, so.

MR. GUGEL: Right. Okay.

(Cross talking.)

MR. HOKE: -- for the synchronization issue just real quick there, and maybe grid forming helps with that, but that's just one piece of the puzzle of the Ride-through, right, everything else that everyone else had mentioned.

MR. CHWIALKOWSKI: Before we go down that path of grid forming/grid following, let's go back to that previous question of, you know, will hardware fix a lot of these voltage Ride-through issues? And I'll go back to the source of truth, but I also want to -- I also want to expand a little bit upon that because as a generator owner operator, we're being asked that right now, what will be necessary to maximize our turbines down in the ERCOT 4 region, for instance? And I want to explain that process to you a little bit better because this is not a trivial process.

We rely on the source of truth, the OEM, to give us that information about the turbine. But that's just the first step because then you take it to the substation, and you start looking at how are we protecting the components of the substation? If I make any change downstream at the turbine level, how is that going to affect my substation? And then once I have a better idea of how that affects the plant on the medium-voltage side and the high-voltage side, then I go back to the -- I hate to say it -- the modeling side, which could take far more time to even go through that process because, again, we look at the source of truth, the OEM for the models. And that could take six months to a year sometimes to get those models from that and then expand the models to the entire plant.

Now, if you have a homogeneous system and you have one OEM, one model type, that works out pretty well. You put two model types out there, it gets a little more difficult. Two OEMs each having one model makes it even more difficult. We have a site with three OEMs and multiple model types. It's easily a year to get a model set together to submit. That's the process that we go through, but again, to answer your question, on the hardware side alone for the turbine, the OEM. I mean, if we can't get an answer from them in a reasonable time, that's where we stand.

MR. LAUBY: I don't want to hear myself. I think the challenge here, too, is to understand what's the risk. I think some folks kind of mentioned this before. We saw some charts that Alex put up on the current situation based on certain events. If we just ask folks to provide us what they can, and I don't know how you define that, what's reasonable versus unreasonable, and then looking forward, making sure that we stay to one particular standard that we can count on. And realizing that, again, sometimes when you do the technical studies, that you may actually not want to implement a Ride-through criteria that might be like a 2800 or 029. Maybe we need something a little bit shorter. I think -- I think we can stay in front of the risk. I think the main -- the main thing is to ensure that those can -- those devices out there that can provide more within the reasonableness that -- you guys can decide what's reasonable versus unreasonable -- to take advantage of it.

There may be some regions, though, or interconnections where that's a real issue for them, and Texas might be one of them. It's a small interconnection, very -- more and more dependent on the inverter-based devices there because they're building a lot of them over a period of time. And so they may have a bit more of a need in certain interconnections versus other interconnections.

MR. GOGGIN: I totally agree with that. I think, you know, the need needs to drive this, not the capabilities, and that was a little confusing this morning kind of hearing the -- from the Drafting Team that they kind of -- you know, that their logic was, oh, well, IBRs can do this, so we're going to make them. And that's backwards, it's discriminatory, and it's just not a good standards practice.

You should define the need, and I think it's clear that the plus or minus 4 hertz per six seconds is not based on any real need, based on, you know, the charts we've seen this morning and the 10 NERC reports. You know, there's never been a frequency deviation that large, and, you know, just thinking about what would happen. If the frequency is down at 56 hertz, every conventional generator would've tripped off, you know, or at 59 hertz, all the load would've tripped off around then, too. You know, what's the point? What are we trying to achieve here by making IBRs stick around while every -- the entire other power system -- rest of the power system goes black?

I don't think -- I don't -- I haven't heard any -- I've been asking all day. I think -- I don't think anybody has heard a good technical justification for what we're trying to do here. You know, these -- the bounds here are just so far beyond, you know, everything that I think is based in, you know, actual needs, and so what is that need? And yes, it may vary by interconnection, you know, the standard connection. NERC has done analysis showing it's -- you know, even with very high penetrations of inverters, maybe with, you know, extremely high contingencies, you know, 3X, you know, losing 7,000 megawatts in contingency, you still have very tightly-controlled frequency.

And with IBRs that have fast frequency response, grid-forming capability, and other things, frequencies are even more tightly controlled with lots of batteries, with, you know, controlled renewables. I think we're moving to a where frequency is even more tightly controlled than it is today. And so let's, you know, first establish that need and then work backwards from that, and then set the requirements based on that. Let's not go with this backwards route of, oh, we can, you know -- we think inverters can do this, so we're going to make them.

MR. GUGEL: The only caveat that I would provide -- and sorry, Mark, I'll speak out of turn, and you can clean up for me. The only caveat that I would provide is the examples that were provided this morning and that kind of show some of the events that occurred, were just specifically rated to -- related to inverter-based resource events that we've seen over the last three or four years. It doesn't say that we haven't seen frequency excursions larger than that. It's just that we haven't recently seen those.

If you go back in history, we have had in Florida somewhat, fairly large, you know, frequency excursions that have occurred. And we're trying to protect not just for some of the things that we've seen recently, but for events that could occur on the system that are much more drastic than that. We're trying to stay out of that.

MR. GOGGIN: Sure, and I was including Uri in that, which was not an IBR. It was a gas event.

MR. GUGEL: Well, yeah, but, again, that's just some of the more recent. If you were to go back to some of our more historic legacy issues that maybe got us into why we got our name and our purpose you would see a little bit more of those issues that are there. And, Mark, I think Edison probably had some good comments --

MR. LAUBY: Yeah, Edison, and I saw that. No, I think you're right, Howard. I think that -- I don't see this as a discriminatory act. I know the Drafting Team is struggling with what -- with the tools they have and the experiences they have. I think the challenge has been that we're saying throw a ball, but we won't tell them how fast we're throwing it and how far it's got to go because we haven't done the studies. Back in the day when you were adding a generating plant, you ran all sorts of different contingencies, and you made sure that you didn't impact your neighbor, that you had all the models right, and you knew how that thing was going to play within the system. It seems that we haven't done that in some -- in these cases, maybe because there's just so -- the number is so large and has overwhelmed the system.

But we have to get back to, to your point, what do we need and how do we tune the system, and that includes the in grid-forming inverters. How are we going to tune the system so the controls work together and provide the self-healing smart, you know, resilient, reliable grid that we envision this is going to result in? Thank you.

MR. PATEL: So may I add something real quick? I think -- I think we have been focusing -- so we're in a football season, so let me give you an analogy. My team lost the football game over the weekend. I'm glad I'm here so I can forget about all that. But they were -- they're a pretty good defensive team, but they couldn't move the ball on offense. You can't win the game, right? So we are talking about Ride-through capability, this frequency deviation for this time. And there is -- a big other side of it is that, what does IBRs do, or any other resources do, when the frequency is abnormal for certain amount of time?

The new IBRs probably can respond much faster during frequency deviation, right? Battery energy storage can respond much faster. I think -- I think we can put some solutions together for the system where the frequency's arrested before it goes too low or too high, right? I don't think we have to only focus on plus or minus 4 hertz per six seconds, or whatever other hertz per 299 second, the other piece, which is not part of PRC-029 right now, which is okay. But I think there are other ways to make sure that the system together holds, right, and the frequency arrested, and it turn around back to 60 hertz in a -- in a timely manner.

MR. GUGEL: Yep. Charlie, I've kind of dominated the questions here. Have you -- have you got anything you'd like to add at this point?

MR. COOK: No, keep going.

MR. GUGEL: Okay. You know, one of the -- and I'm going to go off script here. It's not even a question that we've got here, but one of the things that we saw in the past was an issue with sampling frequency, and the fact that -- sampling frequency. So the issue that may be harmonics or subharmonics may be affecting what the inverter or other equipment sees as being a frequency or voltage excursion, how do we solve that problem? Is it -- is it -- I mean, it'd be very easy to in my mind to say, okay, well, I'll just get some sort of a frequency smoothing device or sampling issues or whatever. But is there -- is there some way that we can maybe address that and come away with a feeling that we're actually sampling what's occurring on the system and not getting influenced by harmonics that might be out there?

MR. HOKE: That's not in the script, but we can say a little bit about it. So right now, Manish and I and a whole bunch of other people in this room are writing IEEE 2800.2, which is the procedures to verify conformance IEEE 2800. And from a really high level, what that does is it takes an IBR unit, which is an individual turbine or an inverter, and do some tests, whether that's in a lab or in a field or even in a HIL setup. And just doesn't try to make sure that it can do any certain thing, but just make sure that its behavior matches its model. And then you take that model or that IBR unit, which is now verified to match the behavior of the -- of the device itself, and you build a plant-level model, and you do a couple -- a few simulations, fairly simple simulations, really, on that, to make sure that it meets the behavior and -- that you need for my IEEE 2800, for example, or from whatever other source requirements document you're looking at.

And so you can use a process like that to verify whether a plant is going to trip, for example, when there's a phase jump and confuse that phase jump with the frequency change and trip. If you can then play a phase jump through that plant model, and if it's going to confuse -- if it's going to get its PLL confused and think, oh, whoops, the frequency's 72 hertz, I'm going to trip, it's going to fail that test. So you can use a process like that.

You would also see it in the testing phase 2 because you would've put a similar event through the event -- through the actual hardware inverter or turbine, and you would've seen, oh well, that turbine didn't behave how we hoped it would. And so I think through that sort of a process, which, you know, like I said, right now we're writing this in 2800.2, but these are processes that manufacturers are already using. Manufacturers are already testing their devices, not exactly using the procedure we're writing because we're writing them now, but they're also validating their models against their hardware, at least I believe all the manufacturers that we saw up here this morning are. And so that's one approach to that question is sort of a testing -- combination of testing and modeling, I guess, would be the short answer.

MR. GUGEL: Okay.

MR. LAUBY: One thought I had on this is, what we're getting to is, you know, inverters themselves have wonderful characteristics of being able to move very quickly. And so we need to be able then to ramp up our sampling or monitoring very quickly because they need sometimes to act at the speed of light to protect themselves. So I think, you know, the -- I think that the sampling rates have to increase or monitoring rates need to increase so that then the remedial actions and mitigations can take place, and also, that that information can flow to other inverters in the area. I'm going off, this is the reason why, and, of course, then they can act accordingly, too.

MR. CHWIALKOWSKI: I'm going to add to Mark's comments because I think this is a great place to digress, as an example, PRC-028, for instance, asking for additional data. I don't know of a single developer generator that would say we want less reliability. That's not the case. That is absolutely not the case. And looking at PRC-028, looking at ERCOT's NOGRR255, looking at IEEE 2800 Table 19, we know this is not easy. This is hard. This is not easy stuff. It will cost money, but it's -- you know, even though it's hard, we're willing to do that because we think data is the answer to move forward, to move prospectively through some of these requirements because having the right data will help us make better decisions in the future.

Yes, it's hard, yes, we're willing to do it, yes, we have a understanding, but it's not wholly understood yet what kind of equipment we'll have to retrofit out in the field to get this data, but we're willing to do it. That's where we come from, and that backs up your comments, too, Mark.

MR. COOK: So there's question from the script that I'd like to have addressed right now, and it's Question Number 3. And it says, what are reasonable solutions to ensure legacy equipment can be compliant with the frequency criteria in Draft PRC-029 Attachment 2?

MR. GOGGIN: Yeah, I can offer some thoughts there, and I think it's instructive to go back to Order 901 from FERC. They pointed to the language that's in PRC-024 that has equipment limitation exemption process, and, you know, there are some things similar in the current draft of PRC-029 for the voltage-related requirements. I think that's what is needed for these existing resources.

You know, I think we heard on the last panel that there needs to be reasonable accommodation for, you know, using declarations or attestations or something like that in cases where it's just not practical to test because, you know, the OEM that built a piece of equipment is no longer there, or, you know, it's no longer supported by the manufacturer, or just, you know, you just -- in many cases you can't physically test for these things. You have to run simulations and kind of guess what it was, and that's -- you know, I think that's -- again, it's why we don't do retroactive standards. In many cases, proving a negative retroactively is extremely challenging. And so there needs to be some reasonable accommodation, yeah. We don't want to have a blanket exemption, but at the same time, like, you know, there has to be understanding of the realities of how you can validate this.

And, you know, I think, again, having this equipment limitation in there is essential. You know, there's a massive cost potentially incurred here if we don't have an exemption for the existing resources. And with, you know, no real upside reliability, it's just going to be, you know, a hundred-plus gigawatts taken offline.

And, you know, I think, you know, we've heard about, you know, what Order 901 says. I think having exemption for frequency is entirely consistent with FERC's directive there. If you read it contextually -- I have a little insight here. I'm not -- obviously, I don't work at FERC and I'm not a lawyer, but FERC was responding to comments that I helped ACP CIA write when it talked about the exemption for voltage Ride-through. And we'd had a back-and-forth in the NOPR, the notice of proposed rulemaking, with FERC about the voltage requirements, and basically we said, you know, there might be some challenges with existing resources, and then FERC was basically saying, okay, you can have an exemption for existing resources that would have to replace hardware to meet the voltage requirement.

FERC was silent on frequency Ride-through requirements because we weren't talking about that in the comments that we were submitting. FERC was clear that they were okay with exemptions for resources that would have to replace their equipment, and, you know, FERC's logic is there's not a lot of these, they're going to be replacing their equipment anyway as inverters age out, and, you know, we're repowering the wind fleet anyway, and so there's no reliability risk here, so we can have these exemptions.

That logic all applies for frequency Ride-through, and so I think, you know, there's very clear logic from FERC as to why there should be an exemption process that looks like what's in PRC-024. And FERC actually, again, pointed to PRC-024 when they were directing NERC how to set up this exemption process.

MR. GUGEL: Yeah. I would even extend on what you said earlier, not only looking at reliability benefit, but reliability deficit for the retirement of, you know, hundreds of gigawatts of energy that's out there. You know, that should be taken into account, too, so I think -- I think that's a really good point.

MR. LAUBY: I would add to that, I think it's important that we understand -- we planning engineers understand what is the state of the network. What is the state of the generators in the sense that when I do my studies and I have an overfrequency, I know which ones are going to go out and which ones are going to hang on. I also want to understand the implications of the ones that go out on the ones that did stay on, and do they create more of a frequency issue. So I think going through the process of -- you know, going through the attestations and understanding the state of the generators that are on the network, plus, of course, those that we're adding, that when we do our system studies, we'll have a much clearer picture of really where we stand.

MR. GUGEL: Yeah. I think, not to get too far off topic here, and we want to go to the questions online and in the room. I think one of the things that today has pointed to is the fact that we need to have these same conversations about models as we get into the next phases of 901. And I think it's going to be very crucial that we get us in the room again and talk about those issues through that. With that, let's see if we have any questions here in the room or online. Bueller?

(Laughter.)

MR. YEUNG: Yeah, I'm on. I had to get clearance from Jamie first before I asked this question because I'm a -- I'm a moderator for tomorrow. But today my question is solely from the ISO/RTO perspective. My name is Charles Young with Southwest Power Pool, and I'm not sure if there's many other RTOs in the room here today, so I thought -- I want to raise this issue.

First of all, I want to point out what Mark said. I'll call that Letter A. Mark mentioned this expanded frequency response provides a lot of automation and adds resiliency to the grid. So that's very important knowing that the proliferation of IBRs is jeopardizing some of that stability, you know, operating in the unknown states, right? The second thing is what Manish said, and I'll call that Letter B. Manish mentioned very clearly PRC-024, it's not a Ride-through standard. It's a -- basically a frequency limitations-settings standard to prevent, you know, resources from dropping offline during conditions or the where the grid is, you know, in excessive frequency declines or rises. So as an operator, as an ISO/RTO operator, I'd like to get to Letter A, Mark's model, the future resiliency and automation, produce light things to work and not have to intervene to avoid Letter B, you know, this relay operation when frequencies are either excessive or high.

So how does an ISO do that? How do -- how do we get resiliency without getting into PRC-024 operations? The only tools we have as operators is operator intervention, and that can be a range of things, right? We can reconfigure the grid, we can put resources on resources online, and, as an RTO, it could be out of merit, more than likely out of merit, or we can do curtailments of those assets we believe are at risk. So that's our choice. I'm not hearing a lot today about the operator's tools and how these benefit the operator.

MR. LAUBY: I left it on this time just in case. I think the way to get to it, of course, as a -- I'm thinking operational planning drop, right? You got to -- like you say, we got to model this stuff. We got to know -- we don't want to be running the system in unstudied states, so we need the information on what the expectations are. How are they going to behave? Every one of these plants, how are they going to be behave under certain system conditions so that when we study them ahead of time, you can pre-position yourself rather than kind of go, oh, surprise, guess what, another thing happened and another thing happened.

The idea that we need a unique models for every one of these, I hope we can get around that, but at some point or another, at least being able to understand that during certain events, what your expectations are going to be. And that feeds right into your IRO standards about contingencies that you're going to run on your system because you have a certain expectation that when a line-to-ground fault comes on, you're going to lose 500 megawatts of solar voltaic, and so then you got to make sure you're ready for that, as opposed to running blind.

Of course you can haul the planners in later on if you want and say, hey, you got to fix this. That's in the planning stage, right? And that's when you start getting into, well, what the standard is and what's -- what equipment we're going to be acquiring going forward. But I think you're -- right now, you're right. You're kind of running a little bit blind because you don't have the models, and you don't have the knowledge of how those devices are going to perform during certain events. You're kind of learning on the fly.

MR. PATEL: So real quick, Charles, I think that's a million-dollar question that we don't know the answer to. I mean, you asked the question from ISO/RTO perspective, but if you think -- I used to be a transmission owner or protection control engineer until recently, and, you know, to protect my system, I need to know what the system will look like or what the system will be able to provide in terms of falcon or what type of falcon, and then I can set a protection. But I think it's a million-dollar question that we don't know the answer to yet. Thinking of 24/7, 365 days a year and then 20 years out in future, right, you have very different operating scenarios when you go through different days, different months, different years, so.

MR. CHWIALKOWSKI: I'll add one thing to that, also, just to answer your question. I think to help you out, we do need better modeling, no question, but better data also is important. I mean, that's two of the things that I think are very important that we can look at retrospectively versus prospectively, where we have the technical capability and it's also commercially reasonable. That's where you establish that balance, right, of going down that path. And I'm going to quote Alex from earlier this morning where he mentioned, you know, what is it that we should focus on moving forward? I think a couple of solutions are right there, right in front of us -- better data collection and then better modeling -- and for that, we need our source of truth, the OEMs. So, Alex, you're there.

MR. SCHMIDT GRAU: So Thomas, Vestas, here. Just kind of a segue of this as well. Grid forming, grid following, at least from Vesta's perspective, is the same hardware. That's different software at current states. So I think it's also important to understand when we talk about the PRC-029, for me, that's a capability requirement. It's not about how the plant has to perform. It's an envelope on it, and with these tools of we're going to get data, better modeling, and so on, what is the kind of vision to start developing some more direct performance requirements on how to do

-- because what are we going to do as an OEM? What should we design our control for if the frequency goes to 58 hertz for hundred milliseconds or 200 milliseconds or 300 milliseconds?

I don't -- I don't see that kind of in the performance on the standards today, and that also creates a lot of different implementation possibilities and different behavior on it. So I'm looking for some direction on performance requirements and how that should look like.

MR. GUGEL: I'll take the first step on that. Nice for the compliance guy to jump in here, I know, and you're all fading. You know, I really would look to the technical experts to develop some reliability guidelines around that. You can kind of think of what we -- what we set up at NERC for reliability standards as being the guardrails, if you will, the extremes. But I think once you operate within that, then really you're looking toward your technical experts to decide what should be a best practice. And I'm going to use air quotes there because everybody's hates to do that because they're public utility commissions, hold to them the different things. But, you know, when you're within that, there's probably better ways to operate and less better ways to operate. I don't think, at least from our perspective, we wouldn't define that in a reliability standard, but instead, that would be more operating practices. Any other thoughts from the -- from the panel here on that?

MR. PATEL: So real quick, I think -- I think -- I think what you mentioned is very important, but I think the answer to some of those questions will be system dependent, right? A 200-megawatt solar on a 500 KV system can perform a little bit differently than a 50-megawatt on a 46 KV system, right? So I think it's very difficult to standardize how to utilize some of those performance requirements. I think it'll go based on system studies and need of the grid, and all that kind of stuff. So maybe your reliability guideline, that kind of provides an educational material to engineers about how to utilize some of those capabilities, but I think standardization is too early for something like that.

MR. SCHMIDT GRAU: It makes perfect sense because

I think it's very important to, you know, as you said, Manish, also, we should have the equipment, try to correct the frequency before we hit the envelopes, and that, for me, goes in into some of the performance. I know we have extremely fast sampling from a plant level. I can talk more on that in one-on-ones, and that sometimes turns out to be very negative as well. In Texas where you have a very small deadband of frequency, we sometimes go in and out of frequency control 25 times in four seconds, you know. So we're re reacting too fast because there's a performance requirement stating you're not allowed to have any artificial delay on your response, so we just like bang in and out, in and out constantly.

So that's where some of these performance and understanding is also faster is not always better. We also have to slow down things, and that's where we need to balance it.

MR. GUGEL: You probably also have situations where you have units fighting each other, right --

MR. SCHMIDT GRAU: Yeah.

MR. GUGEL: As they're popping in and out, they're actually reacting to each other on that too, which --

MR. SCHMIDT GRAU: Ask Todd about that with his three OEMs in one plant.

MR. COOK: Yeah, excuse me. Scott, you stood up while ago, and I didn't recognize you. I apologize. Do you have a question or did it get answered or asked?

MR. KARPIEL: (Off mic comment.)

MR. COOK: Okay.

MR. GUGEL: I tried to lead us there, but, you know.

(Laughter.)

MR. VENKITANARAYANAN: Nath Venkiti, GE Vernova. My question is, I think there is a general intent to try and align PRC-029 somewhat to IEEE 2800, you know, not exactly. But like, the Ride-throughs curves seem to have a basis in IEEE 2800, but there are also some substantial differences, and I wanted to understand if those substantial differences are intentional or if they might actually be accidental. I'll give you some examples.

Like for example, IEEE 2800 has an MFRT requirement, and it starts off with a paragraph, and the first bullet under that paragraph says that the IBR shall not be required to withstand more than four consecutive voltage dips. Okay. That first bullet was picked up in PRC-029. Now, IEEE 2800 then goes on to say in the second and third and fourth bullets that if the voltage dip is less than 50 percent, then it only needs to withstand two consecutive voltage dips and not four. So those subsequent bullets were eliminated from PRC-029, and that kind of raises a question in my mind as to whether this is really intentional or accidental.

Another example, IEEE 2800, the example that I brought up this morning about the one-cycle Ride-through requirement for transient overvoltages. Now, I heard that there is -- there's kind of -- some kind of intention behind that, but accidentally, what that has done is impose a requirement that the IBR units withstand any transient overvoltage that is less than one cycle, an infinite magnitude of that voltage that is less than one cycle, right? That's exactly what it's been translated to.

Other examples: IEEE 2800 said wind turbines, which a typical wind turbine with its blade at its

12:00 position can be -- an offshore wind turbine can be as tall as the Empire State Building. So IEEE 2800 said, if you have mechanical resonances during MFRT events, then the wind turbine is allowed to trip to protect itself from those resonances. That part is not in PRC-029. Another example IEEE 2800 says V over F, for -- right? For V over F, it said -- it referenced certain equipment standards for auxiliaries and said if you go outside the envelope of V over F or F over V capabilities as specified in those standards for those auxiliary equipment, then you're allowed to modulate reactive power so as to adjust voltage and try to stay within those limits so that you don't trip. That requirement was f eliminated from PRC-029.

So again, I'm just asking for the view of this panel is, do you think this is intentional or maybe accidental?

MR. GUGEL: So at the risk of providing a non-answer, I'm not sure that this panel could speak to that because they weren't on the Drafting Team. They weren't the ones that made the decision on that. I think that would be a good question to have the

Drafting Team and then also the Standards Committee as they're looking at making this modification. But I don't know that this panel could speak to the intent as to whether or not it was intentional or not.

MR. VENKITANARAYANAN: Okay. Yeah, I didn't find another forum to ask the question, so I just wanted to see if there was any -- if this --

MR. PATEL: May I -- may I? So with all due respect to Husam and Shawn, I'm not a member of the Standard Drafting Team, but I joke that I'm an honorary member because I'm equally vocal as an observer --

(Laughter.)

MR. PATEL: -- and they value the input that encourages me to talk. I think -- so consecutive voltage dip and transient overvoltage are the biggest nightmares of my life. I'll remember it until I'm dead. The Clause 7 in 2800 -- that is voltage and frequency Ride-through -- is a good 20-page material that was written by a lot of folks very carefully, and PRC-029 is, what, three page requirements document? So we went into 2800 and picked up few tables and few statements and put it into PRC-029.

I think that's the risk, right? This 20-page story in 2800 became a three- or four-page writeup in PRC-029 with all the measures and every other fluff that needs to go into the NERC standard, right, and that's actually the problem. I do agree with you, Nath. I think we have to be very careful that when we go and pick some bits and pieces from 2800 and put it somewhere else, we have to make sure that the dots are connected appropriately so there is no ambiguity or unintentional consequences.

MR. VENKITANARAYANAN: Thank you.

MR. MAJUMDER: I'll just offer this to answer Nath's question that it was not accidental. I'll leave it there. Whether it -- whether or not it was intentional, I would not get into that. But what I would offer is the standard of thinking needs to understand models are very important, but let's not make reliability standard only thinking of PSCAD and PSSE. It way beyond PSCAD and a PSSE. It's a physical equipment, everything Nath just said. Those insights are extremely important, so I'm so glad that in Technical Conference, we have great participation from the OEMs who are sharing their insight.

This is one, in my mind, is a missing piece. The Standard Drafting Team needed to consider that what are the physical insight. Going into a PSCAD model and changing from 1.7 to 1.8 can be done in seconds, but the consequence of changing that 1.7 to 1.8 does not happen instantaneously. There is a massive process that is there, and even in the model, not just mention about the mechanical resonance, not a single PSCAD model would capture this. We have issue of temperature rise on a DC chopper, which model is capturing that?

So therefore, when we get a question like, okay, let's find out what hardware element, I think the previous panel said many times it's not -- you cannot just put your finger one specific hardware element, that's the reason. It can be a very complex combination, so it's not only just an IP. Of course IP is an issue, but the outcome of so many complex element creating a trip, it is -- it is not easy. So let's think beyond modeling space, let's think from an equipment perspective, and listen to all these expert while we are making further decision. Thank you.

MR. BENNETT: Okay. Thank you. I don't think we're terminating this panel just quite yet. I think we can take a couple questions from online and give them an opportunity to participate?

MS. CASUSCELLI: Yeah. Yeah. Thanks, Todd.

MR. BENNETT: Okay.

MS. CASUSCELLI: I'll ask a couple of questions from online. So most of the discussion so far has been for land-based resources. Are there different voltage-related concerns for offshore wind?

MR. GOGGIN: I'm not going to get into the technical details. I would note part of the reason why I have mentioned the need to have the standard apply prospectively from the signing of the interconnection agreement and not being placed in service as it is in the current draft is because of the long lead time for offshore wind, but also, you know, other land-based wind, you know, and solar and batteries also can have long lead times between, you know, when they sign the interconnection agreement and -- I'm sorry -- when they, you know, start developing the project and, you know, buy equipment and develop settings and things like. And so, you know, having the requirements take effect for plants in service as is in the current draft would not work for these longer lead assets. And so that's -- you know, that's necessary to, you know, set the requirements and have them take effect based on resources -- signing the interconnection agreement after the date, you know, the implementation of the standard.

MR. LAUBY: I was talking to my friend from EDF here because they have a lot of offshore and, you know, many times the collector systems are DC, and one would have to do the study work to see if that has any implication. But certainly they're more rugged offshore than they are onshore, but that might be one study that needs to be done, see if there's implications of the AC-to-DC collection and the -- another set of inverters there.

MR. GUGEL: Probably interconnection methods would be another way of looking at it, whether or not it's radial or whether or not it's connected at multiple points, because a radial one would have different voltage issues, I would think, than something that would be more of a network connection.

MS. CASUSCELLI: All right. Thank you. One more from online. The OEM panels do not seem to represent all of the vendors, and so how does NERC plan to address the different IBR technologies that were not represented on the panels?

MR. GUGEL: I guess a good answer wouldn't be we're just going to make up some stuff for the rest of it.

(Laughter.)

MR. GUGEL: No. So there's -- this is still a very public process, and I know the Drafting Team in the past has tried to reach out to OEMs to get as much information as they can. I'm hoping that we have even more OEM representation online at this point. I know that the Drafting Team and others would welcome any comments and any input that you would have from your perspective on that, too. Certainly from active OEMs, we know there's also some that, you know, are no longer in production. It'd be very difficult to get information from those, but kind of information that can be provided to help further a knowledge about what is out there on the system and what is going to be projected out there in the future would be very much welcomed.

MR. GOGGIN: I would just chime in that this is all the more reason to not do retroactive standards. It's extremely challenging to make sure that those standards work for everything that's out there, including the stuff that was built decades ago by somebody that no longer exist, and prospectively to use 2800 because it's what the industry is designing towards, and so that process has already played out. You know, Order 901, we're having to do this very quickly and that approach of not retroactive and IEEE 2800 prospectively is the safest way to avoid causing major unintended problems.

MR. GUGEL: Yeah. So I understand the concern, but we have many standards that are retroactive standards when they go into place. So I understand that we need to -- we need to have a concept and a -- and a -- and a -- and a -- and a context of how this all fits in, but just because something is a legacy piece of equipment doesn't mean it needs to have reliability issues and reliability constraints placed around it as it operates on the system because it can affect reliability just as importantly as things that are placed in the future.

MR. GOGGIN: Yeah, I don't disagree with that. I think, you know, again, if we do have concerns about existing resources, we should start with the, you know, reliability needs and work backwards from that and design a solution. You know, this is an extremely fast process, and we need to be careful we're not causing unintended problems in this process. We can -- if there are real reliability concerns that are left on the table I think there's an opportunity to come back and address those later. But I think there's much greater upside -- or downside risk of, you know, taking off -- unintentionally taking off large amounts of operating resources and causing a reliability problem than there is in, you know, maybe missing a reliability problem that might emerge at some point in the future, then we can fix that later.

MR. PATEL: May I -- may I say a few things? I think I agree in general that legacy equipment cannot be detrimental to the reliability of the system, right, but I think we also need to look at a little bit bigger picture. I wanted to mention this when Alex was presenting earlier today, is that all the disturbance reports that have come out in last seven, eight years, those were because of something like momentary cessation or incorrect measurement of frequency, things like that, a spontaneous reaction of controls to system disturbance.

When we are talking about frequency Ride-through, I think we are talking about plus or minus 4 hertz per six second. So I think if we fix some of those issues that were actually brought up, right, in disturbance reports then -- and then we make sure that the new IBRs do provide frequency response in a manner that we don't actually get to the boundaries, right, I think -- I think we'll have our problem solved.

MR. GUGEL: I think potentially that's the case, yes. The only caveat that I would provide to that is, we continue in every one of these disturbances to see more things that come up, and I think being reactive for each one of these is not really a long-term solution for reliability. I think, instead, if you set the parameters and then -- I hate to use the word "force," but have generator owner, operators, OEMs, others go out and validate that they can perform within those parameters, then you don't get into the situation where you fix one problem, and then a year later, you have another issue that occurs on the system that is somewhat related, but not exactly the same as what that previous one was. I think that's the concern that, at least we've seen from NERC, is that yeah, we go out and fix things as they happen, but you can't just continue to be reactive. We need to at least draw a line in the sand and say, these are the performance parameters that need to be met.

MR. LAUBY: Yeah, I agree with you Howard, and again, this gets back to handwaving. We got to get beyond handwaving and actually do the hard work, do the modeling, do the simulations. I don't know if what you say is true or not until I see the runs, so we can't do it heuristically. We got to understand what the risks are that are mounting on the grid and how do we mitigate them, and what's the pathway to the end state.

So I agree with you a hundred percent, Howard.

MR. HOKE: One other quick comment on that, though -- so I see the -- I see both sides of this. Like, I see wanting to go back and fix some of the older stuff, at least the stuff that can be fixed, without going to extreme measures, but I also see the side of, we want to get a Ride-through standard through in a reasonable time frame because in the meantime we're installing even more legacy stuff day by day. And so maybe there's a path where we separate those two things, just put that idea out there, where the legacy -- the legacy retroactive stuff maybe is separate from the -- from the forward-looking stuff.

MR. GUGEL: It might be a good conversation for some of our panels tomorrow, I think that'll be good, yeah.

MR. BENNETT: That's kind of what I was thinking, also, on this is maybe this is a good spot to break for today. I will let everybody know that we have collected many questions online. And today, I think we're going to run out of time to do the Slido polling and kind of go through that exercise, but tomorrow there'll be an opportunity for that, and I think we're going to circle back to some of our online themes tomorrow once we have -- can maybe discuss that a little bit more internally. So I think with that, how about we give everybody a round of applause for this great panel.

(Applause.)

MR. BENNETT: So yes, not just this great panel, but everybody today. This was very informative, this was a great session, and I do think we have maybe just a couple small things here at the end. Sue Kelly's with us today. She is our -- first of all, she's a NERC Board member, and she is the liaison to the NERC Standards Committee. And do you have any remarks to share here at the end of the day?

MS. KELLY: I do.

MR. BENNETT: Would you like to come over here and share them or share from over there?

MS. KELLY: (Off mic comment.)

(Laughter.)

MS. KELLY: I just want to thank everybody who came today, both virtually and in person, and I want to thank the Standards Committee members who are doing all of this work on top of their day jobs. Very much appreciate that. And I want to thank the Drafting Team because I know they've spent countless hours working on these issues, and I appreciate those who came today to explain the decisions they made and why they made them. We owe them our thanks.

I want to talk a little bit about what I've heard today. This is a scary thing for me to be doing it, but I'm going to do it anyway. First, I think the more information that we have, the better, and the earlier that we have it, the better. I think that's one of the things. A lot of stuff is coming out today that if we had had earlier would've been better.

David Ortiz noted that FERC issued Order 901 based on the record before it. They did what's known as notice and comment rulemaking. They gave notice, they took comments, and then they made a decision based upon the comments that they'd gotten. And in retrospect, there might be some people who wish they'd been more active earlier on in that docket at FERC, and there's a lesson there. That lesson is be there or be square.

You really need to participate both at FERC, and now we're obviously following onto the work that FERC assigned us, so it's important to be active earlier rather than later.

Second, what I heard is that the role of the original equipment manufacturers is crucially important. They need to be part of the dialogue. I'm glad they came today and spoke about their concerns, and I hope they stay engaged. We heard a lot about the inability to comply with certain of the proposed requirements of PRC-029. I hope they, in turn, leave today with a better understanding of our need at NERC to ensure that their equipment does not contribute to reliability events in the future. And more and more of it is going to be installed, so that issue becomes more and more important.

Third, I loved Alex Shattuck's Venn diagram. I love Venn diagrams from sixth grade. It's one of the few mathematical concepts I was able to absorb. How much future Ride-through performance should we demand from our resource base, and how much are we going to have to pay to get that? We cannot use today's regional grids and generation mixes to decide how much is enough because, again, as David pointed out this morning, we're anticipating a very quick ramp-up in IBR-based resources. And so the ground is shifting under our feet, and the requirements are going to have to shift as well.

The conservative reliability-based response is to do what I would call the Ride-through standard equivalent of belt and suspenders to, you know, make sure eight ways to Sunday that we are covered on reliability, but that could come at a very high cost, so we have to balance those things as we go through this. We also need to consider the issue of legacy generation, as was just referred to, and the efficiency and effectiveness calculus that Alex laid out for us may be different for these resources than for new ones.

So I'm going to be thinking about all this tonight, and I'm sure you will as well. Hopefully we'll have another productive day tomorrow. We'll be back 9:00 tomorrow, and I will note that breakfast and lunch are up one level -- this is my most important duty -- up one level in River Birch A, and there will be signage to direct you. Breakfast will be available at 8:00. I hope to see everybody there. Thank you very much for your time and attention and deep thinking today.

(Applause.)

MR. BENNETT: So with that, Sue shared my logistical information, so I believe we're adjourned for the day. So thank you very much, Sue.

[Whereupon, at 3:49 p.m., the Technical Conference was adjourned, to reconvene at 9:00 a.m., Thursday, September 5, 2024.]

CERTIFICATE OF TRANSCRIBER

I, Charlene Williamson, do hereby certify that, to the best of my knowledge and belief, the attached transcript is a true and accurate transcription of the indicated audio recording.

I further certify that I am neither attorney nor counsel for nor related nor employed by any of the parties to the action; further, that I am not a relative or employee of any attorney or counsel employed by the parties hereto or financially interested in this action.

9/9/2024
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Transcript of **Technical Conference Day 2**

Thursday, September 5, 2024

Conference for North American Electric Reliability Corporation

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

(NERC)

Standards Committee and NERC Ride-through

Technical Conference

Thursday, September 5, 2024

9:01 a.m.

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SYED AHMAD, FERC
MELISSA ALFANO, Solar Energy Industries Association
HUSAM AL-HADIDI, Manitoba Hydro
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TODD BENNETT, AEC, NERC
KELSI BOYD, NERC
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BILL ZURETTI, EPSA

AGENDA

AGENDA (continued)

P R O C E E D I N G S

MR. BENNETT: Okay. Good morning, everybody, and welcome to Day 2 of our technical conference. We've seen a lot of familiar faces here back in the room, and I think we're starting to fill up online. So just want to welcome all of our online participants as well as those in the room.

As far as major notes this morning, I don't have a lot to add other than I'd just like to encourage our participants to continue the momentum from yesterday and the engagement from yesterday. It was top notch, and I can tell you there was a lot learned from it, and it provided a lot of good data points to help the Standards Committee move forward. So with that, Soo Jin, do you have anything you'd like to add?

MS. KIM: All right. I will be very brief. I just want to say thank you so much for everyone that participated yesterday. I think yesterday was a really great day. I think that we got a lot accomplished, and I think we heard from a lot of different voices that I think filled in a lot of the gaps for the different issues that we saw come through on the comments with regards to the standard.

I would be really remiss if I did not thank the people who put this event together. I cannot tell you what a tremendous task it was to get this type of a conference put together in just a few weeks. So Jamie Calderon, first, I want to thank you because I don't know if everyone understands under her leadership, we've done so much work. And we've had to coordinate with so many different departments and had to bring so many people together just getting these panels together, just getting everyone informed, putting together this agenda, it was under her leadership, so I just want to thank you for that.

Also, we have a tremendous staff here at NERC, and so Levetra, Tiffany, Wanda. Also, the staff that could not be here today: Alison Oswald, Nasheema Santos. I can't -- the list goes on and on about how many people had to come together to make this event happen. All of your hard work is so greatly appreciated, and we know we could not have done this event without the tremendous effort that came together in just a very short amount of time. And when I say everyone was working late at night, early in the mornings, just to make sure that this event came through very seamlessly, not only in person, but online, we owe them a tremendous gratitude.

And then I, also, for the other departments that are contributing, the engineering staff, Alex Shattuck, J.P. Skeath, all of the other engineers that have put together a tremendous amount of technical input, provided a lot of advice, thank you for being here. Howard and Mark, thank you for your leadership and also being here today. Robin, Sue, thank you so much for your participation and all of your remarks because, again, it has been a very collective and collaborative effort, and I think that we are moving forward, and we're making a lot of progress. Also, I just would like to thank the SC members. We did get some volunteers here to lead this SC effort. It is not just a NERC effort: Todd, Amy, Troy, Charles, everyone who's volunteered, thank you so much because after today, there's going to be a tremendous amount of work to get a next draft put together.

I just want to remind everyone of our charge. When the Board invoked Rule 321, there are several obligations that we have to meet. And so I just want to remind everyone that we are addressing this particular project. I know based on the comments that have been coming in, many people would like to see an expanded effort. There are some comments asking us to open up other standards. I just want to say that we have to focus on this Ride-through issue. That is the next task. That is what's going out for ballot. We won't be opening any other standards, and we will be focusing on the particular issues that we had to address with regards to Rule 321, and that is with Ride-through.

We get one more ballot, and again, tomorrow starts the new drafting effort. It will not be just a blank sheet of paper. We're taking into account all of the comments. Nothing that has been submitted online or submitted to NERC staff is lost. And so I know that we had a limited amount of time, and there's some consternation with regards to submitted questions. Everything is being reviewed. We are taking a tremendous amount of time to walk through all of the comments. And this is also a very transparent and public process, and so we are very committed to that, not just as a department, but as NERC. And so I just want everyone to be very assured that if there's any concerns, please reach out to me, and we will make sure that comments are addressed. We were -- or have to walk through the process with you again.

And the last thing I just want to say is that as we are required to under Rule 321, this will go out to Ballot One more time, and we have to conclude this effort by the 30th. And so I just want to remind everyone, we are under a very tremendously tight deadline, and so by the 30th, we have to conclude this process in order to present something to the Board in October at an open call for adoption.

And with that thank you so much for all of your time. I look forward to today's discussions, and I thank you again for being here and online.

(Applause.)

MR. BENNETT: Okay. Thank you so much, Soo Jin, for those sentiments and kind words and details about the path forward, so thank you so much.

So moving right on into our agenda today, I see we have a panel discussion on Frequency Right Through Exemptions in PRC-029. So today, I believe Charles is going to be -- help us be a moderator that as well as Alex from NERC, so I believe that if we want to get our panel together, we can commence.

(Pause.)

MR. YEUNG: Okay. Good morning. My name is Charles Yeung. I'm with the Southwest Power Pool. I'm a member of the Standards Committee, also vice chair of one of their subcommittees, the Project Management of Standards Projects.

Yesterday we heard quite a bit about the frequency Ride-through requirements and how they differ from, of course, PRC-024 and also the IEEE 2800-2022. Today's panel, we're going to be talking about what was left out of the current draft, which is exemptions from frequency Ride-through requirements. So as I mentioned yesterday, we heard quite a bit about a lot of the obstacles and challenges to meeting PRC-029 frequency Ride-through. So today, our panelist is assembled to talk about, you know, what exemptions would have as far as an impact on how the industry can move forward as far as IBR Ride-through requirements. So Alex, you want to ask the first question, and we can down the panel?

MR. SHATTUCK: Sure. Yeah, we'll get started, and we'll probably just ask one and do follow-ups as we go down the line. So our first question today is -- for the panelists is, what are the financial and practical impacts between hardware- and software-based solutions? And Mark, you can us get started.

MR. AHLSTROM: Sure. Mark Ahlstrom. I'm representing NextEra Energy. You know, I think we have to be careful not to underestimate the impacts of, you know, the complexity and the effort of software as well because, as we know, with all the emphasis on modeling and getting all the analysis done, you know, even doing a software upgrade, you know, it takes a lot of engineering analysis, working with every --, you know, every OEM for the various pieces, not just wind turbines or the solar inverters themselves, but the balance-of-plant issues, you know, coming up with an engineering redesign creating the models, verifying the models.

And as I -- as I wrote in my comments, you know, that has to be done on a plant-by-plant basis. Every plant is different. Even if you're using the same OEM for a particular wind turbine, for example, you might have different converters. We've got more than 10-plus converters in our NextEra fleet, you know, so it takes a lot of effort. And then, you know, literally, you're talking about having to go out, even for software, to many dozens of plants and many thousands of turbines. And I did put in my written comments by the way, that -- if you'd like to see them, I'd be happy to share them with anybody even if -- I don't know if NERC is going to post them or not, but I'm happy to share them where we went through the entire fleet and looked at the impact, and we'll get to that for the various curves in a bit.

But I think software impacts are reasonable to bring up to 2800 compliance. I think you have to allow a couple years to do that because it's a complicated process. The hardware upgrades are an order of magnitude more difficult because all of the engineering with that, and also, like, with wind turbines, you have some up-tower things, you know, you can't --, you know, it can be much more expensive. But both of these are complicated processes, and we should not underestimate the impact of either of them.

MR. MACDOWELL: Yeah. Thanks, Mark. You kicked us off well. Good morning, everyone. Jason MacDowell here. I actually wear two hats in industry. I've been with GE Vernova's Consulting Services for the last 25 years, and, really, you think of GE Vernova as an OEM. Certainly GE Vernova is an OEM. We have a lot of OEM stakeholders here and participants that you heard from yesterday. I work in a group that really focuses more on systems integration, working not only as an OEM, but more representing system operators and system integration.

But the hat I'm wearing today is the second role I play in industry as the chief system integration officer of the Energy System Integration Group. Just like Mark, we have multiple roles, and Mark representing ESIG as well in some of this -- the industry work that he's doing as president of the board there as well.

So I wanted to just build on what Mark was saying relative to the cost implications, and I think, Mark, you alluded also to schedule implications, which is the next question. And I think, you know, we all recognize that any upgrades that are needed, whether it be software or hardware, is more than just toggling a bit or just installing a part. There's a lot of rigor from a manufacturer's point of view, and all the way across the chain with the developers, the plant owners, equipment owners, the system operators, the utilities that needs to be done to accommodate any changes relative to what we'll call standard application products, right?

And, you know, when there -- if there's a need for a software upgrade or a hardware upgrade, in order to account for that and understand the implications of the benefits of those changes and, ultimately, the impacts on their -- on the performance of what they will do to the grid and to the plant design, as Mark alluded to, is looking at the overall implication to the fleet, looking at the overall implication to that set of products. That includes a lot of engineering analysis. It includes a lot of analysis on the implications of the overall integration of the wind turbine or the solar inverter and the solar system or the plant for that matter. But it also includes a substantial amount of effort to really understand the implications in terms of modeling.

And then there's the open question of when you do the modeling, you got to validate, but what are the aspects that you need to validate that may cause a material change, right? And no doubt any software/hardware implications that we have are to improve the performance, but there are still -- there's the reality that the system operators and the utilities do have processes for interconnection and material change clauses, that if you do change something for the better or otherwise, if you make any upgrade, there is a process to reevaluate that from a system impact point of view, right? So I think those are all of the considerations and costs that go into system upgrades and what's needed on existing products.

For implications on new products, there's a new product, I would say, introduction or integration and new technology integration evaluation that all system -- all OEMs will need to do and be able to communicate that through models, through documentation, and that takes time as well. So it's -- again, any changes that are made are made deliberately to look at how the product will respond and what is the implication of those changes relative to the lifecycle of the equipment and the -- and also the impact that that would have on the rest of the grid.

As Mark also alluded to, any of those changes, particularly around frequency, really depends on the technology, and it depends on the overall design. So it's not as easy as a broad sweep to say, oh, that one change to meet a wider band of frequency Ride-through is going to have this implication on this product for this amount of time. It really depends on the overall design.

There's probably, and I'm reaching out a little bit, and I would love to hear some feedback from my OEM colleagues because this is ultimately an OEM question about the cost implications. But really the -- one of the biggest implications, especially on, you know, a system like a wind turbine and also, you know, other aspects like solar inverters and what have you, is looking at the impact of frequency deviation on auxiliaries, right? And those auxiliaries are not --, you know, are not necessarily implicitly modeled in a lot of the system models when we look at the overall performance.

And I tell you know, I was on the first PRC-024 Drafting Team back in 2007 when we started this journey long time ago, and on -02 as well, and that was the first time that I had experienced, you know, the NERC drafting team process where FERC mandated through Bob Snow, and, Mark, I think you remember Bob, you know, his comments there well, that we needed to have a standard that was completely technology agnostic.

At that time, the Ride-through curves on both voltage and frequency were more difficult. At the time we had a lot of debate about what is fair, what's reasonable, what's capable, what does the system need relative to the technology at that time, over a decade ago. And it was far more constraining for synchronous machine technology, especially on frequency relative to inverter-based technology even at that time. And I think that's also the case today where we have frequency deviations that are a lot more sensitive on rotating equipment that are not inverter based than the inverter based. And I think we have to keep that in mind, too, about when we go down the path of looking at the costs relative -- the cost of compliance relative to what the system performance will be, and how each resource will be, you know, integrating and looking at their -- the individual performance.

We're engineering a system. We're not engineering one piece of the system in a bubble, and I think, you know, that's a big consideration around the cost of compliance relative to what we expect from renewables to Ride-through compared to the rest of the system. So I'll leave it at that.

MR. ROGERS: Maybe to take just a little bit of a different course because that explains some of the technical difficulties at a high level pretty well. Maybe look at what the actual practical impacts are going to be and financial impacts for the -- for the GOs and how that -- how that has to be considered to some extent.

What we've heard a lot today is we don't quite yet know what it's going to take, especially for these legacy -- you know, these much older legacy and even some of the stuff, you know, built in the past decade, what it's going to take to be able to allow those to meet the requirements as set forth in the current draft. We just don't know. What is that cost going to be? Again, we don't know. We don't even know if it's possible in some instances.

So right now with this, you know, and looking specifically at the discussion around exemptions for frequency Ride-through, if passed today as written, we don't know what the impacts -- reliability impacts specifically, but also cost impacts, to eventually the end users, what those reliability impacts are going to be to the bulk power system. We have no idea, and that hasn't been quantified yet. Does frequency Ride-through capability, ROCOF, everything, all these technical issues that have been discussed, do they need to be considered, especially moving forward? Absolutely. I don't think anyone in this room saying that that's not the case. But right now, where we sit today, if the standard was to pass as written, we don't actually know what the reliability impacts of the bulk power system would be, and there's a chance that it could be a net negative. And I think that's something, when you're looking at a reliability standard, you have to take very heavy into account.

So I think I'll just leave it at that. There's some really excellent discussion about the technical aspects that I'm not going to be able to talk, so -- or top. So I think that's just really my takeaway is right now, when we're looking at financial and practical impacts, we don't know what those are going to be, and especially with the practical impacts, we don't know what the scope of that's going to be. We don't know how bad it's going to hurt. Thank you.

MR. GUGEL: So Howard Gugel, vice president of regulatory oversight at NERC. Not sure I can really opine on the financial and practical impacts of these, but I just want to opine a little bit on an area that I can, and that's the reliability impacts. You've heard that a little bit earlier.

You know, we're in a situation even today where in some of the markets, there are times when 99 percent of the energy being absorbed by the consumer is being done by inverter-based resources, green resources. If in those scenarios we have frequency excursions that take those offline, nobody's going to ask after the fact what were the financial and practical impacts? They're going to say, why didn't you guys solve this problem before we got into it? And that's -- I'm not saying NERC. I mean, that's going to be industry as a whole, that we need to make sure that we've got that on -- that in our focus.

So, but I think also you've got to take that into account with what are the practical and financial implications of that. I'm not saying that you throw that out the door. I'm just saying that if we get into a scenario where we are almost entirely being provided energy by inverter -based resources, and we know that there's an issue with frequency Ride-through or voltage Ride-through, and we haven't addressed somebody's -- that we're going to have a lot of questions that we'll have to answer at that point. So just, I think we need to take that reliability impact into account when we think about the practical and financial impacts.

In addition, you know, we -- you heard yesterday that projections are at this point that potentially by the end of the decade, we're going to be at about 50 percent of resource that will be inverter-based resources overall, not just at certain times of the year. And so we need to ensure that the traditional benefits and reliability impacts that have been provided by synchronous generators can still be provided on the system. So you've got to look at that impact there also.

MR. YEUNG: Alex, do you have any other comments or questions for the first question?

MR. SHATTUCK: Nope. Nope. We can move on to the next one.

MR. YEUNG: Okay. So thanks, Panel. Obviously a lot of unknowns on costs, especially from Dane, his comments, but of course, the other dimension of implementation and compliance to PRC-029 is how long does it take, so the next question is about a timeline. So what is the timeline of this one, specifically about software-based updates, necessary to meet the PRC-029 frequency Ride-through requirements, and how does that differ with hardware based? Yesterday we heard some comments that even if it's a software-based solution, there could be limitations or requirements for hardware upgrades as well. So the question is, how long does it take to do software updates for PRC-029, and does that differ from hardware?

Also, I'd like to add one more dimension based on a lot of the discussion we said yesterday. This question is asking about meeting PRC-029 criteria, but if you can also add whether that changes, whether it's 2800-2022 criteria instead of the PRC-029 criteria. So you want to go this way?

MR. GUGEL: I don't think I can opine on that because, again, that's kind of outside of my bailiwick.

MR. ROGERS: Yeah. Again, the technical aspects are going to be better handled by the two gentlemen to my right here. But one thing, again, I think that I can speak to is, you know, from our discussions with our -- with our OEMs, is the uncertainty on this. We've been told, you know, it may be possible for some of the equipment, especially with legacy equipment, it's a -- it's a big unknown if there are going to be software updates that are possible. And if there's hardware updates, I mean, to some extent, when you -- when you use the term, "hardware," eventually it is going to be possible, right, if you go far enough up and build enough things out, you change enough things, you're going to get there. But at what point does that become, you know, much more like a repower and not an update? Not certain on that.

But again, I think the primary concern, at least from where I sit, is the uncertainty around this and the inability -- the inability for us to know if software-based updates are going to be available for these, if hardware updates are going to be available for these, not necessarily just the timeline, but are they going to exist? And then if they do exist, what is the timeline, and I don't have answers for that, again, back to the uncertainty.

MR. MACDOWELL: So the reason I'm pausing here is because I think, as always, the answer depends. It depends on the nature of the upgrade and whether it's software or hardware based. Like I alluded to and what I just said earlier, it's more than just toggling a bit or just installing a part, right? There's a lot of rigor that needs to go into evaluations on the overall equipment, on the integration design, on the modeling, on the validation, on, you know, evaluating if you need to do anything more from the interconnectivity point of view. So, you know, the question I think was aimed at how much -- how much time does it take manufacturers to decide how to -- how to change things from a software or hardware perspective, but we really need to look at the overall picture of the implication to actually get that deployed and to get it in place so that, you know, the implication of that software or hardware changes realized on the grid.

Software changes obviously tend to be a bit quicker than hardware upgrades as a general point of view, but not always, right? It depends on the amount of analysis that's needed. Generally, with frequency responses, as I said before, we're looking more probably at some of the evaluations on impact on the auxiliaries and not, and then that brings up the question, well, how do we represent that at all in our capabilities and modeling? And that's typically, generally through the Ride-through curves and the protection that's applied to fundamental frequency phaser domain models, and maybe in a little bit more detail in EMT models, right?

But to generate those curves, it sounds simple, right? They're just a bunch of stepped-based curves that are overlaid with the frequency and the voltage profiles that the models are given. But it takes a good deal of effort to actually generate those curves, or at least look at the impact of any changes that are happening and see whether there is an -- you know, a need to reevaluate the curves themselves. And that is in a series of systemic, design-based modeling, and also, if needed, testing, depending on the upgrade.

So that whole process can take on the order of weeks to months, sometimes even longer, depending on the implication, for a software upgrade. For a hardware upgrade, it could take on the order of years, right, to go through the overall testing and capability implications on the turbine and on -- you know, ultimately leading up to the modeling and impact on the rest of the grid. So I think it's not an overnight thing. It's something that needs to take in careful consideration on, you know, ultimately how long it's realistically going to take to get this overall capability deployed, not just changing, you know, the software or hardware in the equipment itself.

MR. SHATTUCK: Okay. Before we move on, just to make sure we compare the things we talked about yesterday, but do you have any kind of thoughts, Jason the difference between a timeline for meeting 029 draft language and 2800?

MR. MACDOWELL: Yeah. I don't have any specific things yet because we haven't done the evaluation specifically relative to everything we have, and, again, I'm speaking on behalf of ESIG --

MR. SHATTUCK: Yep. Mm-hmm.

MR. MACDOWELL: -- not on behalf of GE Vernova. But generally, you know, and many of you know Julia Matevosyan, chief engineer at ESIG, who's been very, very much in the NERC/IRPS -- you know, with you, Alex, in the leadership of IRPS. This has been a central discussion overall, not only with PRC-029, but Ride-through, and there's a lot of discussion and debate about the overall implications of that. And I think, so going back to the discussion that you and I had, Mark, maybe even last week, you need to do the analysis, right? There needs to be a set of studies to look at what specific things are you trying to fix? What are the specific issues that we know that are out there?

And I'll caveat this, Alex, with your question to say you did a really nice job outlining what is the real issue in your presentation yesterday morning, looking at all the events that have happened, the frequency deviation on those NERC events that are primarily driven by other things outside of the implication on frequency, right? You have momentary cessation. You have all of these questions about how solar will respond. In some cases, there was a little bit of wind in that, but it was mostly solar responding. The frequency deviation due to those events that were on the order of a gigawatt to maybe gigawatt and a half had very little implication in terms of the grid frequency itself, so it wasn't a frequency Ride-through issue really at all. It was other things that needed to be coordinated and modeled and taken care of.

So I would say, let's look at the issues that we're really trying to resolve, understanding what the real implications are, and then try to solve those instead of having a theoretical what if this happens. And, you know, let me take a step back in PRC-029: what would really cause a frequency deviation that would be that big? You would have to have a very, very large deficit of instantaneous generation tripping offline, very large power plants, likely not renewables at this point, maybe could be if you had gigawatt class renewables, but it could be large nuclear plants. It could be a large part of the grid tripping offline that would cause, you know, an underfrequency or a large load like data centers, multiple gigawatts tripping offline, causing an overfrequency. Could be a large HBDC station tripping offline that caused that event. It's really not renewables that would be the cause of it, but we want to make sure that in those cases, that we don't have a disproportionate of any type of generation tripping offline causing a further reliability risk, right?

So those are the types of analyses that we need to be doing. What are the design basis events that we see today? What are they -- what are they looking forward? And I really think that, you know, as we transition from a world that has a lot of synchronous machines today -- large nuclear, large coal to renewables -- those design basis events from that perspective are going to get a little bit smaller. But with the data centers that we're seeing and all these large loads that are integrated, those design basis events may be causing us to get bigger. So let's look at that, understanding what the frequency deviations are and try to solve for that, and understand what the implications are across all the fleet. And I think that would be much better placed to understand the system.

Now, the last thing I'll say about PRC-029, and I will say something about GE -- put my GE hat on just for a second. Several years ago, GE Consulting was commissioned to do a study for the Wind Energy Institute of Canada, backed by the renewable -- the Canadian regulator, and worked with David Jacobson, worked with all his system utilities across the board to understand what was the impact. And the big thing that we took away from that is that Manitoba and Quebec had very large and wide frequency bands in their Ride-through characteristics because there are very specific system needs for that. They have large HBDC connections in remote parts of the grid that, on purpose, really created the need for these wide frequency Ride-through capabilities.

And the Canadian grid codes for those provinces tackled that, but generally in most other places around -- all of the interconnections across North America don't need that wide frequency ban. It's covered by the grid codes there, but we want to make sure that we're looking at fit for purpose across -- a need across all of North America. And then if there's any specific needs in any region, making sure those regions have the protections in place to suit those particular needs as needed.

MR. SHATTUCK: (Off mic comment.)

MR. AHLSTROM: Sure. I actually think we do have pretty good emerging evidence about the size of the elephant with regard to costs and effort and the difference between the 029 curves and the 2800 curves. Now, NextEra, of course, has a lot of solar and storage, but -- in addition to wind, but we've been in wind a long time. And I'll give specific numbers actually for Question 3 in terms of the exact difference in terms of megawatts and turbines for 029 curves and IEEE 2800 curves.

But let me just start by saying that we've done a thorough analysis of -- based on the information we had available from our OEMs and everything on the plants. NextEra has Type 3 and 4 wind turbines. We have 27 gigawatts, 150 plants with 13,700 turbines using 14 major turbine models with sub-model configurations in addition, four wind OEM models, and more than 10 converters. These go back as far as the early 2000s.

You know, and based on discussions with the OEM so far, our estimate is that, you know, using the 029 curves, I'll just mention here briefly and I'll go into details on the difference with others later, 66 percent of those turbines would require a hardware exemption with the current PRC-029 curves. Now, that's 22 percent of the gigawatts, 66 percent of the turbines because we're talking mostly about older wind turbines, obviously, you know.

So as I said, I'll go into details about how that's improved by going to IEEE 2800 or -- and how that compares with PRC-024 in a moment, but, you know, that's what we're looking at here. We understand the hardware impacts of this, I think, quite well. We don't have specific costs because we don't have the quotes on -- from the OEMs and the other components and all that, but, you know, this is a substantial impact that would have hardware requirements, you know.

So I guess we'll just go to the next question. I'll give more detail, but, you know, that gives you a side -- you know, we actually -- I think other independent developers out there, other renewable developers are doing a similar exercise. Everything I just mentioned is documented in my written comments, and I'd be happy to discuss it with you in more detail.

MR. SHATTUCK: Thanks, Mark. So yeah, we'll --

MR. GUGEL: Real quick, that there was something that I could weigh in on the points that I heard. And Jason, if I could, with all due respect, I do understand wanting to look at actual scenarios and things, but part of what we're charged with doing and part of what our industry is charged with doing is considering what-if scenarios.

Our reliability coordinators and our transmission operators need to understand predictably how units are going to occur on the system and how they'd be able to do in an emergency operation system. If they don't have that, and if what we're saying here is that we really don't understand, in general, how that's going to happen, I am concerned that they're going to be flying blind. So part of what we're doing with PRC-028, 029, and 030 is providing that predictability for them to be able to understand, at a minimum, for units going forward, but also understanding where we're at a place right now, if that makes sense.

MR. MACDOWELL: It does. Yeah, completely agree, you know, and I think that forward predictability is complex and it's difficult. And one other thing that we've been really focused on at ESIG and also with GE Vernova with some of the planning work that we're doing with system operators, is really focused in a lot more on integrated system planning to the regard of understanding where are the real pinch points, right? And a lot of the planning that has been historically, and with no fault at all. It's just the systems that have been planned out today have practices that have been in place for decades around understanding where are the system stress conditions on peak load, on light load, maybe a shoulder condition.

And those conditions are no longer the biggest risk. There are other risks around peak IBRs that are not associated at all with peak load, light load, or traditional shoulder conditions. There's peak ramping needs relative to the variability and uncertainty of inverter-based resources, variable energy resources.

There's limitations on headroom for frequency response and Ride-through. Understanding what those system conditions are and try to solve for those, and what is the frequency deviation and frequency response going to look like in those system conditions? Absolutely, right?

So that's what I was saying is, looking at this deterministically and a bit stochastically with integrated system planning saying, what do we expect when we see penetrations of renewables going out to 2030, 2040, and understanding what those frequency deviations really will look like, and then what is the resource mix that needs to respond to that and be resilient against that. And that's all I'm saying is use a forward-looking view with integrated system planning to help plan out those scenarios.

And perhaps, you know, I have to give credit to the Drafting Team. Being part of NERC drafting teams in the past, I know how difficult it is to balance a lot of these issues when we don't have all the resources to do deep technical studies, right? There's a lot of work that could and should and probably would be done if we had a different organizational structure, but realizing that, you know, the drafting teams have the limitations that they do with the visibility on what's looking forward. But I think this is an opportunity to look forward more, not only for Ride-through, but looking at integrated system planning as a core part of our practice moving forward across utilities, across, you know, NERC requirements in response to Order 901, in response to 2023, in response to 1920. Those are the things that I think we have an opportunity to look a lot better at and really define what problems are we trying to solve. That's all I was saying. Thank you.

MR. SHATTUCK: Thank you. Well, we'll get into the detailed question here, Mark.

(Laughter.)

MR. SHATTUCK: So Question Number 3 here is, do you expect equipment to fail to meet the frequency Ride-through criteria as specified in Attachment 2 of draft PRC-029 due to hardware limitations? And there's sub-questions just to kind of quantify them, but, you know, what's your estimate of products that would be affected? How does this change if you consider 2800, and how does this change when you consider PRC-024? So, you know, any estimates or real numbers or megawatts would be super helpful for kind of quantifying all of this.

MR. AHLSTROM: Sure. Well, yes, there are hardware impacts, and I've got the numbers here. So with the PRC-029 as drafted for the wind fleet that I'm looking at here, you know, we'll have to do a similar analysis on solar storage, but it's not quite as substantial there. We estimate that 6 gigawatts out of the 27 gigawatts would require an exemption for frequency Ride-through due to hardware limitations. That involves 9,000 turbines, all four of our window OEMs, and all 10-plus of our converters, so it's quite substantial. It's much significantly improved by moving to the IEEE 2800 curves. That would still be 4.5 gigawatts out of the 27 impacted to some extent, 6,400 turbines, but just two of the OEMs and two of the converters that would have to be -- have hardware upgrades. How does that change with respect -- you know, if you go to PRC-024? It's only 200 megawatts that would require exemptions, 200 turbines, one OEM, one converter model.

So clearly it could be argued -- you know, I think IBRs should actually do what they reasonably can to support the grid. I'm a huge believer in grid services, reliability services, as you know, and that inverters are going to be cornerstone of the future. We, you know, so I'm not saying we shouldn't go to the 2800 curves. It could certainly be argued that it's discriminatory, but I get that it's, you know, what can we get out of this technology. But the reality is, you know, with PRC-024, you know, we're basically compliant today with the wind fleet, and I think also with solar and storage, you know.

So it could be argued that the technology agnostic fair path would just be to say, look, all legacy stuff, just continue to comply with PRC-024. All new stuff, as soon as we can get the new OEM models out, you know, you comply with 2800 curves. And a good reason, by the way, of complying with 2800 is I think that will be our stepping stone toward grid-forming inverters that we're trying to accelerate as fast as possible, so within hopefully five years or so, you know, we can have a fair number of -- a fair share of those inverters doing grid forming, which would further, you know, support the grid and the grid services and the response to the disturbance there as well. And that provides our pathway forward toward 2050 when, you know, I think the legacy fleet will be a minuscule piece of the IBR fleet at that point, and the IBR will be state-of-the-art, you know, inverters and enough grid forming that we have an extremely good, stable set of grid services to deal with this, in addition to balancing and flexibility and so forth.

So I'll leave it there. The difference between PRC-029 as drafted and 2800 curves is significant and has a big cost impact, and certainly on the number of hardware upgrades and the cost and effort to get those done. Thanks.

MR. MACDOWELL: Yeah. So I want to parse this answer again with my ESIG hat on. And I think the general consensus of what Mark just said is that the difference between the proposed curves in PRC-029 relative to 2800 is substantial. Exactly what are the numbers across the fleet across North America, I mean, I think we still need to evaluate that just because of the evolving nature of the standard. But I think especially on, like you said, Mark, on legacy units, we've been well served with PRC-024 to date. According to what you've said so far with your analysis yesterday, there was no implications that any of the big events that have happened over the past almost decade were due to a frequency Ride-through issue. And for existing units, there's really not an issue that we're trying to solve today.

To your point, Howard, what are we trying to solve for in the future, right? We need to evaluate that, but I think the very, I would say, the middle ground that seems to be the most reasonable at this point, we put a lot of thought into the 2800 requirements, as Mark said, and manufacturers are really engaged in getting all of the capabilities built into the new equipment. There are certain areas that are looking at retrofits, and I think some of you know, some of the things that are happening there. But by and large, most of the 2800 capabilities and requirements are achievable with a reasonable amount of effort in terms of the capabilities.

Compare that relative to what's proposed in PRC-029, that's a much bigger gap that needs to be overcome with a substantial cost -- potentially a substantial cost and a substantial timeline to that. And I go just back to my points before is, one, there is that substantial amount of effort and cost and time that's relative to what's proposed in PRC-029. We want to make sure that it's a cost that is very well understood and very well spent to understand is it really the problem that we're trying to solve, right? So going back to fleshing that out, when do we need to solve it? Is that really an issue in all systems, or is it an issue in a specific system that we're trying to scale in ways that don't -- doesn't necessarily need to be scaled across interconnections? Well, we can't answer that question yet without having the analysis done to back it up.

So going back again to the integrated system planning, evaluating what scenarios would we need any sort of Ride-through capability from any resource, not only inverter-based resources, to me, is a very critical step along the way.

MR. ROGERS: Yeah. So again, focusing on -- more on specific impacts, I guess, to generator owners and, you know, speaking for -- you know, my opinion on OG&E's position, as well as a lot of the other GOs who are connected to our transmission system, we have a pretty aging renewable fleet, specifically talking about wind, in our part of the country. And answering the question specifically, do you expect equipment to fail to meet the Ride-through requirement, the criteria in Attachment 2, yes. We have approximately 500 megawatts of wind that we own. All 500 would fail to meet the Ride-through criteria in PRC-029 as written.

Looking at IEEE 2800 and PRC-024, that shrinks significantly. One thing that does not change, though, is still compliance with PRC-029, even if you were to make the modifications and shrink the -- you know, shrink the Ride-through zone to something a little bit different, is rate of change of frequency. When the equipment that we have installed and many others in our part of the country was built, rate of change of frequency wasn't a design consideration. It wasn't something that was talked about. There were probably some industrial standards that took things into account for specific pieces of hardware, but to try and apply that to the system as a whole and say that it's even capable of -- to state, you know, with the rigor necessary to demonstrate compliance with the reliability standard, that it's capable of performing at any given rate of change of frequency, would be very difficult to generate any such claim and be able to stand behind it.

Now, that's not to state that it can't do -- you know, do so. It's obviously withstood frequency changes that have some rate of change of frequency, and it can do so. But what is that, how do you determine it, and then how do you have evidence to demonstrate that you're capable of doing so is a whole nother question. And I'm not -- again, this kind of comes back to the uncertainty. How do you even determine these things for this? You know, us as generator owner, we're in a very difficult position with our resources to try and be able to make these determinations, relying back on the OEMs to some extent. And then when you talk about the difficulties, you know, with projects, hardware and software, and everything else, that the projects were probably kicked off a lot of this stuff in the late 90s -- mid- to late nineties -- with installation had taken place in the early 2000s. Getting those archive designs out, trying to build up what these are actually capable of on things that weren't necessarily considered at the time of building, and then presenting a GO with an estimate on what these things, you know, can actually perform in these -- you know, with these parameters, such as rate of change of frequency or frequency Ride-through capability, how long can we, you know, withstand a whatever, 4 hertz frequency change for -- you know, can we do it for 6 seconds, can we do it for 3 seconds, whatever the case may be.

And I'm going to lean back a little bit on some, you know, some different industry experience I have working in manufacturing. So when you start talking about all these legacy components that are in these devices that were built a very long time ago, they were spec'd out to a very specific thing, right? Everybody specs everything out. We gave -- you know, we gave the requirements to the -- to the OEM. The OEM is then going to give those requirements to all their subs. Those requirements are what was built to at the time.

There may be variations in components that are in these things that are not necessarily -- we're not able to account for today because they met the requirements that were given to all these subcontractors, everyone that built your parts, but they're still going to perform differently on criteria that weren't accounted for, and that's something that you were going to see across the fleet on a lot of these things. So again, it gets back to this concept of uncertainty with -- especially with these legacy equipment. So I want to be very careful to make sure that I'm not saying this looking forward. This is about exemption criteria for things that were built in the past, especially, you know, kind of at the beginning of the transition, so to speak.

So when you're looking at these assets that were put in the ground, you know, say circa 2005, there's aspects of this that we can -- we're quite certain we can comply with, especially looking at IEEE 2800 and PRC-024 with the -- you know, with the bands as far as frequency with your curves for frequency Ride-through. But there are other considerations that just aren't necessarily accountable for and that we'd have to rely on the OEMs to some extent to give us that information. And, you know, kind of with some insight I have that some of that information is going to be very, very difficult to state with certainty that, again, meets, you know, again, back to what we're talking about here, reliability standards, that meets the criteria to demonstrate evidence of compliance with a mandatory and enforceable zero defect reliability standard. And that's going to be very, very challenging for a lot of these older assets.

MR. GUGEL: Well, that was a little loaded. So I'm going to probably reserve my comments until we get to the legacy thing because I think that's something we're going to have to deal with throughout all this, but very much appreciate the comments that I've heard so far. I'm hoping at some point we get away from the mindset of zero defect and start talking about effects on the system, but yeah, let me -- let me reserve until we get to the legacy issue.

MR. YEUNG: Okay. Thank you. Thank you. Can I get a time check, Jamie?

MS. CALDERON: We have plenty of time.

MR. YEUNG: Okay, because we have three more questions and d

MS. CALDERON: There's plenty of time.

MR. YEUNG: Okay.

MS. CALDERON: (Off mic comment.)

MR. YEUNG: Okay. All right. So the next Question Number 4, I think, Dane, you alluded to it. Again, thinking in terms of what kind of exemptions should be allowed for frequency response -- I mean, frequency Ride-through capabilities. The question is, for GOs, what are some of the difficulties you might have in obtaining the data to assess your compliance from the OEMs? You know, what are -- you know, is it available especially for legacy equipment, as you said. And again, the context of this question is about the need for exemptions.

MR. AHLSTROM: So again, this comes back to what is currently available on this, and what is currently available is what was provided initially on build. So we know what the -- if you look -- you know, so if you look at a lot of this equipment, it wasn't necessarily even in the -- framed in the context of Ride-through capability. But you're looking at, lack of a better term, tolerance bands, bands of operation this equipment can successfully perform through. You know, and sometimes it's given in, you know, plus or minus percentages. Sometimes it's given in, you know, absolute hertz, whatever the case may be. But that's, you know, that's what we have currently, so as far as the difficulty in obtaining any further information, a lot of that is going to fall back on the OEMs to provide this based on analysis of these -- of these older -- of these older equipment, the -- you know, the components that went into it, how that -- how that stacks up and what the outcome of that is.

So I don't think I can accurately speak to, you know, what the -- what the technical challenges are going to be because that's -- you know, that's not something that I'm going to be privy to as far as the efforts that are going to go into performing these analyses or potentially testing, or some combination of both, on these legacy assets to determine what the -- what the capabilities are. But for us right now, you know, the difficulty is that, you know, that information doesn't currently exist in a lot of cases, especially for this -- for this very -- you know, relatively speaking, for what we're looking at here, old equipment.

MR. AHLSTROM: Yeah. Jason wants me to go next as a GO, and then I can turn it back to him as an OEM in this case, I guess, because, you know, look, this is going to take a highly cooperative, collaborative process between the GOs and the OEMs with regard to the IBR devices we're talking about across the board. And we heard a lot of this yesterday, that, you know, the IBR are still on a very fast learning curve, which means that we're going to continue to see dramatic price improvements where they get cheaper and cheaper, but it also means that they are innovating more on the scale of electronics and software rather than on the traditional scale of generators as we know it, right, which means every three to five years, they're coming out with a whole new generation of inverters, in particular, turbine -- you know, wind turbines.

So in other words, the whole -- all of the engineering expertise of the OEMs is devoted to a new product line, as we heard about yesterday, building for that next product version. They don't have, you know, their development engineering staff looking at the older devices. They're looking at what the next one is going to be. They've retired the test bench on all this stuff once they've done that and taken that old version out of production. As those of you who go through the interconnection process, no, we have a problem with -- you know, I wouldn't call it a problem. It's an opportunity, I think, with IBRs that, you know, if you had -- if you're delayed for several years to get through the interconnection queue, by the time we actually get our, you know, our GIA, the model of equipment we may have thought we were going to use is no longer in production. We have a better one available, but it's different, you know, with different models and so forth.

But that's the reality, and that's the advantage of IBRs is that they're innovating to respond to what the grid needs and what the market needs faster than we've ever done with conventional resources. But that does create this challenge that, you know, how do you -- especially with retrofits, I mean, you have to -- I think, by the way, it's beneficial to have a hardware exemption process to encourage everybody to immediately get started on looking at what are the impacts with their OEM, you know, rather than just you get to the compliance period where, okay, here's what I can do. And then you say, well, that's -- you know, we think you could do more, and then you have to go back and go to the OEM again, and it just delays the process and delays the implementation actually.

So I think 2800 with an exemption process makes a lot of sense, but you have to be sympathetic that, you know. We're not -- it's not easy to get the engineering talent back on this. And then we got to balance a plant, you know, the plant models that have to -- or the GO's responsibility with some other consultant or other in-house experts, you know. It's a big deal to figure this out, you know.

So I think I'll leave it there, Jason, and let you take a, you know, next crack at it. But the logistics, the -- you know, the process of doing this and getting those retrofits out to the field, you know, it involves the OEMs as well as the GOs, and it's highly complicated. You know, you don't -- it's not a slam dunk, whether it's software or hardware.

MR. MACDOWELL: Yeah. That's why I had him go first. Well put, Mark, you know, and I completely agree, and nd to me, you know, the question is well founded about what the challenges are. I think it certainly goes beyond just documentation. And documentation is one element of it to look at what those legacy units are capable of, and then, you know, also realizing that those legacy units were designed to a particular fit-for-purpose form earlier mentioned. And now we're looking at a, you know, a situation where we need to have, you know, looking forward, a much broader set of capabilities than that equipment was necessarily designed for or tested for, modeled for, integrated for. And this is where that communication comes in very -- in a very deep way as needed between GOs, OEMs.

And I'll also say, from an OEM perspective, and Arne pointed this out yesterday in the OEM discussion, is that it's not only the OEM, but it's really a matter of all of the packaging of all the components, all the equipment, all the -- all the auxiliaries that the OEM has to pull together in the wind turbine, in the solar and battery resource, right, and any other resource for that matter. Same thing with gas turbines, right, or steam turbines. There's a whole bunch of complex systems behind the fence that have to be coordinated.

And a big deal about that documentation and capability understanding is that some of those legacy units are sourced with equipment from companies that maybe don't exist anymore or that have substantially changed. So it trickles down or trickles up, however you want to think about it, to understanding how do you go back and reevaluate those legacy systems for, you know, all the components that maybe don't have companies are around anymore, or at least don't have documentation for that old -- that older equipment, and that may not exist anymore, right? So it is -- it is more complicated.

You know, if we were to have a test bench that we could test for that old equipment, that would be easy, but it's not easy to take an existing piece of equipment that's been in the ground 15 years or more and pull together a complete test regime that typically is done in a lab environment where you have a lot of capability to replicate the grid. And many of, you know NREL, CGI, and there's other test facilities that are out there for this purpose. That lab environment and type testing environment is there, fit for purpose for performing thousands of tests under very specific conditions. How do we replicate that in the field to renew the capability that we want to do with a piece of equipment that's in the ground, and, you know, and we need to retest for another purpose that it was never meant to do. So I think those are some of the biggest challenges, right? It's not only about documentation. It's about the entire testing and modeling process it takes again, to show, hey, how could we be compliant or not?

Now, that said, it's not that everything is going to be all incredibly difficult. If it's a small change that's needed, we can do some sort of analysis in some cases and say, okay, we'll have a sense whether it's -- it has a big impact or not, but there still needs to be that evaluation. And that evaluation, if you take any OEM's fleet at tens of thousands to hundreds of thousands of units, you know, depending on who, where, what, how, it really does get, you know, a substantial amount of effort that's needed in that with resources that are fully focused on meeting the needs of the requirements, PRC-024, PRC-029, whatever it happens to be, IEEE 2800, on new units alone. And we don't have an unlimited number of resources to look at both, so I think that's the balance we need to strike. Thank you.

MR. SHATTUCK: Thanks, Jason. I think you're last, right?

MR. MACDOWELL: Was I last? Okay.

MR. SHATTUCK: It seems like the last question might be a bigger discussion, and we probably covered a lot of the next question. So I would say let's maybe be mindful of our time for this next question so we can spend it on questions from the group and the final question. So we'll go with our fifth question, which is, what difficulties do generator owners have when attempting to coordinate their plant to successfully meet criteria specified in Attachment 2 of the draft PRC-029? I think we all alluded to a lot of this so far, so yeah, just keep it -- be mindful.

MR. AHLSTROM: Yeah, very, very briefly. I think the bottom line is all of the OEMs we're talking about are global OEMs, part of the global supply chain. As we heard yesterday, none of them have a product in plan that would be compliant with the PRC-029 curves. 2800? Yes, you know. So I think you have to look at this from a supply chain on a global basis. If anything, we're trying to move toward global unified IEEE-IEC standards, I think, for IBRs in the future because of this global supply chain nature. And, you know, not complying with 2800 is not going to fly in terms of being able to get the equipment we need and be in production with this. And I don't -- I don't think the advantage, if there isn't one, you know, justifies the disruption in that and how much that would slow down and increase costs for the U.S. market on those products as well. So it's just really not a -- not a starter for me.

MR. MACDOWELL: I think I probably addressed this in my last comment as well. So I would like to maybe take the opportunity to talk a little bit about a related subject on exemptions, particularly, because I do think there's a big benefit to the exemption process, specifically, in terms of the fact that exemptions will get you a level of documentation, right, and understanding maybe what the gaps are, and I think that is valuable. Exemptions also take effort, right? Exemptions do take a certain amount of capability to actually look into what the difference maybe would be relative to what the old products are. So it's not that you get a free pass even if you get an exemption, but what you do get out of an exemption is at least an understanding of maybe where the gaps are, right?

And that in itself for planners, for GOs, and OEMs is valuable to understand what are the gaps in the performance that we see today based on the models that were provided and integrated of the plant at that time, relative to meeting a certain requirement, like the Ride-through of PRC-029. So I think that's my plug for at least considering and having an exemption process in place for frequency Ride-through that allows us visibility as to why we can't meet something.

MR. ROGERS: No, I think that was -- that was quite well stated. You know, as far as the difficulties in attempting to coordinate the plant, you know, it goes very much hand in hand with what we talked about previously, having all the necessary information, having the necessary parameters, and, you know, knowing all these things from your plant, top to bottom, to be able to run the appropriate studies and determine, you know -- you know, are they coordinated appropriately as per the draft standard.

I think, again, everything that was just stated was very spot on as far as the need for exemption and what that allows, and the benefits that that does provide as far as, you know, having not just a blanket write-off, you know, can't meet it/move on type exemption, but having something where you really fully document the known capabilities of the plant. You also document the unknown capabilities because, you know, it -- as we stand right now, and maybe this changes as OEMs, you know, are able to develop more information on these legacy pieces of equipment, that'll shrink. But right now, there are some unknowns, and documenting those unknowns are -- you know, would be very beneficial as well for anyone who's attempting to assess the reliability of the system as a whole. And, Howard, to get to your point just a minute ago about, you know, moving from that mindset of zero defect, mandatory enforceable, to looking at the impacts of any particular thing on the reliability of the bulk power system as a whole, I think the exemption criteria really does help with that because it allows for what information we do have, especially right now. What information do we have today right now that, by the time that this -- you know, this standard gets filed with FERC and then becomes effective, you know, we'll have -- we'll probably have more information. The OEMs are probably going to determine some things, but we're still not going to have it all. But that will allow for whatever in information we do have to start immediately flowing, and I think there is real benefit for that.

You know, Alex, some of the stuff that he talked about yesterday with those studies and everything, it allows for further examination within -- with that new information on where the risks are, what are we seeing, what's causing these issues, what other things -- you know, what systemic things do we have? Are there things specific to this location that we can -- that can be mitigated outside of this very specific issue of frequency Ride-through, and what things can be done to address those more systemically? And so sorry, I rambled a little bit, got a little bit off topic, but building off of what the previous commenter said here, I think that that's -- you know, there's a lot of benefit in that.

MR. GUGEL: Yeah, I would agree, and certainly, at least personally, I'm a supporter of trying to figure out some way of finding an exemption that would work. I think as we get into the next question, we'll probably get into some of the more technical details on that, and hopefully they haven't started the vat of tar with the feathers out there for me when we get to that topic. We'll see.

MR. YEUNG: Okay. Thank you, Panel. Our last question hopefully will wrap up a lot of the things that have been discussed, and I believe it will based on this last -- the responses to this last set of questions. Last question, it's kind of lengthy. I don't know if everybody has the actual wording, so I'm going to read through it as clearly as I can, and then kind of give a little kind of a summation about what the question's asking for.

So the question is, many commenters have said that it would only be fair to grandfather existing facilities and those in construction facilities -- the ones that are already in the pipeline -- grant them exceptions from Ride-through requirements due to the cost of retrofitting, and we've heard a lot of that. Other commenters have said that their facilities have an expected shelf life of up to 030 years, meaning there may be facilities in place well into 2050, and at that time, IBR penetration is expected to be much higher, the system will have changed, and that they are not able to comply with the requirements that are written today, these PRC-029 requirements. So how should NERC balance the burden on generators, the cost burdens, who may be asked to incur large retrofitting costs with the burden on the transmission owners, the planners, in my case, operators, who like certainty, and the end use customers from poor or unexpected IBR performance?

So in a nutshell, that question is asking about really the -- there's going to be a lot of industry costs, effort to meet the frequency Ride-through criteria, but there needs to be a balance between those costs and the benefits they have to the system reliability.

MR. GUGEL: Yeah, I would agree, and this is the point at which I'll be able to lean in, I think, a little bit more. I do think we've got to carefully construct some exemption criteria because it only makes sense. The last thing we need to be doing is retiring additional capacity out there when we know the margins are already tight at this point. So that's -- you know, to me that's off the table.

I think where it becomes a little bit more difficult when you start sharpening your pencil is how do you define "legacy?" If I've got a piece of equipment that's been out there for 15, 20 years, and I do a software upgrade or a hardware upgrade, and have the ability at that point to make a change, is it still considered to be a legacy piece of equipment? Would I be required to make sure that I can meet the new -- the new requirements, whatever they are, that we set up for PRC-029? You know, at what point does a piece of equipment no longer meet the definition of "legacy," but it has enough new pieces of equipment that it's -- that it's considered to be something that should be brought up to speed?

And then the other, I think, complicating thing that we have here is, you know, there is a significant amount of generation that's in the queue right now, especially offshore wind. There's some sites out there that they're talking about being larger than 2 gigawatts connecting onto the system, which is just --

I mean, it's huge. First time I heard about that, my eyes glossed over and I got very panicky. Would that be considered to be in construction at this point if it's in the queue, or would -- you know, would it also be that we need to take those generating units and make them comply with PRC-029? Those are the questions that I think we need to struggle with.

At some point, we need to draw a line in the sand say, no new generation that's put in place, IBR based, can be put in that doesn't meet this criteria. And whatever the criteria that's developed eventually for PRC-029, you know, we need to make sure that we've got a date certain that says after this point, nothing new can go on the system that doesn't meet the performance requirements that we have in this. That's just my personal opinion. I know that creates a lot of documentation issues for generator owners, for OEMs, and trust me, it's going to create a lot of issues for the auditors as they go out trying to figure out what's what. But it's the right thing, in my opinion, to do, both making sure we have the exemptions for existing facilities, but then also making sure we've got a line in the sand that says, we know going forward that these units will be able to perform in a certain way.

MR. ROGERS: No, I think that was very well said. You know, there's really nothing to disagree with that. You know, I think we need to be careful, though, kind of looking at the question specifically, when we start using terms like "grandfathering in" and then, you know, "cost of retrofitting," and things of that nature. So grandfathering in, specifically, maybe I would disagree with that concept, right? Like, if you look at something and it was built prior to whatever, you know, it's good, right? Just wave a hand, bless it off and we're done with it, and I don't think -- I don't think that's the case. I think, again, it gets back to these very detailed exemptions. You provide all the information you can about your equipment, and you do the best that it can do to provide these services, right, this frequency Ride-through, this voltage Ride-through, this, you know, withstanding rate of change of frequencies. You ensure that it can do the best that it can do. You know, it's not just it's old, well, let it run, it's good, that's fine.

So I think, you know, we need to be careful whenever -- you know, and speaking as a GO, we need to be careful when we look at concepts like this. We need to make sure that the equipment in the ground is performing at the best that it can do. Now, then I think you also need to stay away from terms, or potentially stay away from terms, like we heard a little bit yesterday about like "maximization" and "maximizing capability," and what does that really mean because a lot of this stuff, again, you're looking at very specific design parameters that this stuff was put in the ground with, and you need to ensure that you're operating as such because, otherwise, you're looking at, you know, well, let's push it a little more, let's push it a little more, let's push it a little more.

Well, now we're running risk of this equipment, and what's the bigger reliability risk now? Is it this -- you know, and especially in some pockets of the country. And maybe this is actually different in different areas, but, you know, you're looking -- you know, we're out here on where we're located, on the western edge of Eastern Interconnect, and we haven't seen a lot of -- a lot of the same issues that maybe have been witnessed to other places. So if we're performing the best that our equipment can perform, we document our known -- our known issues, and we submit those to the relevant people, who need to perform the studies to see what is actually capable, and what we need to be looking out for, and what else we need to be mitigating, you know, I think that's where this goes. I don't think it's necessarily this grandfathering in clause.

Also, when we talk about, you know, balancing burden and retrofitting costs, and, you know, you've got the burden on the TOs and the transmission planners, and, you know, reliability coordinators, whoever the case may be, and you're trying to balance that with the cost of the GO to do stuff. Again, I think at some -- at some point, you got to look at this from a GO perspective. The cost of doing business is providing -- you know, being a reliable partner in the bulk power system. We have to do that, and we have to do that best of our ability. And with this existing equipment, as you've heard many people up here state, that probably involves exemption criteria to some extent. I'm not sure I have much else to add. I think we'll probably get some better feedback specifically from the OEMs on some of this as well.

MR. MACDOWELL: Yeah. Thanks, Dane and Howard. I think that was really well said. I think going back to quantifying the problem we're really trying to solve, the easy answer is, you know, don't leave any performance on the table that's easy to extract. If it can, it should, right? A blanket exemption really might have the unintended consequences of leaving some performance on the table, so making sure, though, we're understanding of those plants or those resources that may have limitations. I think the bigger issue is having visibility to when they do or when they don't.

And some of the aspects of when these pieces of equipment may not be able to meet some of the requirements, especially like what we're talking about in Ride-through, are not necessarily visible in the models that we have, right? And the model -- and this is not only an IBR issue. This is an issue across power system modeling ubiquitously across the board.

Synchronous plants have the same issue. We don't model the auxiliaries in detail in synchronous plants either. We tend to look at the power system's impact of the main power circuit and have a very rough estimate of the Ride-through capability with those simple Ride-through protection curves that are overlaid, that represent a lot of the capability.

Let's talk about a thermal unit, for example. It's the protection of the auxiliaries. It's the fuel path in a gas turbine that is very complex, a lot more complex than the auxiliaries in a -- in a -- in a wind turbine or a solar inverter. Those have the same limitations, right? And I think it's that level of understanding that is very important to have in terms of what is the real reliability risk.

Another aspect that, you know, going back to the discussion you and I had, Mark, last week, really trying to quantify those conditions that we're trying to solve for, so whatever that happens to be, right? Whatever curves that you land on or whatever system conditions that you're trying to land on, do the homework with understanding what the future system conditions look like, right? Understanding, you know, there are different scenarios of future renewable build-out, future load build-out. Those are the system conditions we're really trying to solve for. Going back to integrated system planning, again, understanding what the implications are for those future conditions, and then understanding the implications of things like Ride-through on that, and having that serve as the guide to determining what those curves really should look like.

Some of that was done, to a certain degree, in getting feedback in the process of 2800 from the regard of having a future-looking case or future-looking cases to really get to the point of the problems that we're trying to solve from a system needs point of view, right? And that's why I think the process that we went through in 2800, generally, was -- had a lot of feedback, and it was -- it really serves as a good baseline for the problems we're trying to solve going forward. But that said, I think what's missing in our planning processes today is this viewpoint of doing the system analysis on these future cases to identify all of those system conditions that none of us really have had to plan for up to this point.

So I would say that is probably the more -- the bigger need than to really evaluating, hey, are we going to meet PRC-029 curve or not with system equipment? Do we need an exemption or not? Well, you know, that's only getting us halfway to the reliability issue and really mitigating that reliability issue at hand. That's my opinion. Thank you.

MR. AHLSTROM: Yeah. This question was added actually to the question list late last week, and my initial impression was that this is a real red herring question. You know, I think it actually applies more to conventional resources than it does to IBRs, to be quite honest. I mean, everything we said -- asked in this question applies to what about the -- you know, the thermal fleet in 2050, right?

As I pointed out, you know, we're on a very fast learning curve with IBRs. There's a lot of reasons why even though it -- they may have an engineering life of 25 years or so, we're actually replacing inverters much more frequently than that. We're doing a lot of, you know, repowering of wind plants more frequently than that. There's lots of drivers because the technology keeps getting better, more capable, and less expensive. So when we re-contract it or whatever, we'll put in the next version of equipment to get, you know, more energy into the next contract or whatever, you know.

There's lots of drivers for this, not just incentives by the way, but other business reasons why we're actually -- like with a battery storage plant. I mean, you're -- almost the entire life of the plants, you're upgrading with additional storage in there to maintain full capacity and, you know, upgrading inverters as well. So equipment is going to be replaced/repowered much more quickly with the IBR fleet than it is with a conventional fleet. When we do replace it, we can't -- we won't be able to buy an inverter that's not compliant if we force the OEMs toward 2800 here and what we're doing here.

So without question, you know, I agree with Howard that, you know, when we repower, that we should be in full compliance with that, and I agree with Howard very much that, you know, we also have to look at balancing resources and all that. I think we're going to see a lot of innovation on that from the IBR side as well with the longer duration storage side that we can't predict by 2050. It's not like we're going to stop looking at what new standards are becoming necessary between now and then, you know. We will probably have additional standards that apply to this and additional, you know, things we try to do to improve the fleet, both conventional and IBR.

And I must say, this concept and the question about imposing a burden on transmission owners and transmission planners, this is what TOs and TPs do is they -- the reason they get a regulated return and always have in all the decades of thermo fleet is to reliably and economically deliver the energy from the generators to the loads, right? Why would it be any different with IBRs, you know, but I have very little sympathy on this burden part of the question.

But, you know, fundamentally, I think, as I pointed out, with the technology going on here and our path toward additional capabilities and IBRs, including grid-forming capabilities. The thing to do is to build your way past this so that the future IBR fleet, which will dwarf the size of the current legacy IBR fleet, is highly capable and will support an entire grid with the grid services and the balancing services and everything we need to maintain reliability, which is what we're all here for. And it serves the IBR interest in no way whatsoever if this creates reliability problems or has any reason why we would slow the deployment of new technologies to the grid.

So I'll leave it at that, but, you know -- you know, I don't -- I don't think -- even I don't think that it's wise to be thinking that, well, we have to have a hundred percent IBR fleet by 2050 or anything like. We have to coexist with other resources, including legacy resources, including thermal resources, you know. So I think we can do that, and I think that IBR should be expected to step up to the plate by going PRC-024 to the IEEE 2800 curves, and do what they can with the capabilities, you know, that are reasonable and cost effective, and can be -- can be deployed, and get it out there and do the right thing. So I'll leave it at that.

MR. GUGEL: Yeah, Mark, I would kind of add into that that I think that word "burden" was just a little bit misleading there also. We've talked a lot, and I'm going to stray away, I think, a little bit from the panel here, but we've talked a lot about the limitations and stress at that point. There are some really good advantages that inverter-based resources can add to reliability. And I think as we go forward and understand that, the fact that they can react much quicker to system disturbances and be able to dampen those disturbances quicker, we're going to find that there are some advantages those resources have that we could never get out of the conventional fleet.

And so I feel a little bit disappointed that, in some respects, we've concentrated on the negative yesterday and today.

MR. AHLSTROM: Yeah.

MR. GUGEL: There really are some good, positive things that are going to come out of this.

MR. AHLSTROM: Yeah, and in my comments, I alluded back to what we did on the ERSTF and so forth. You know, there are quirks of conventional resources that we're very used to because we've been dealing with them for a hundred years, right, you know, like, after a disturbance. Do you really want a really slow responding resource where you have to inject a whole lot of energy to get it back up to 60 hertz? No, you know, that's not an advantage of inertia. The recovery is slow. It's mind-boggling is slow compared to what IBRs can do. In fact, with IBRs, now we have to worry about, well, how fast do you want us to be because we don't want to be too fast. We create instability. I get it, right? But that's what we have to work out is there's advantages of all the technologies. We have to figure out how they fit together for system benefit.

MR. MACDOWELL: One thing I'd like to just conclude with, and on a positive note, right? I think we all recognize that there are big challenges that we need to overcome. And these challenges, fundamentally, are the fact that we're a victim of our own success, right, and it's a good thing. The fact that we're seeing a lot of the change that we're seeing in the transformation really going towards meeting bigger goals, to meeting policy needs for planning, decarbonization goals, a hundred percent of something by sometimes, somehow just go do it. Well, the do it part is actually, you know, what we're really struggling with right now. How do we actually make that happen?

And I'd like to offer maybe, you know, maybe some platforms of discussion to consider where we can help each other. And those platforms many of you are already engaged in. First of all, want to congratulate the Drafting Team, first of all, for really a job well done and understanding how to wade through all these issues, but also want to congratulate the work done by the NERC IRPS, the Inverter-Based Resource Performance Subcommittee led by Alex, led by Julia Matevosyan, led by Ryan Quinn in the past, and, you know, a lot of input and really great discussion to understand what the issues are and how do we mitigate them.

And one of the things that we're doing in ESIG in the Reliability Working Group, specifically, and I work with Mark with ESIG and lead that working group with Julia Matevosyan, is understanding the implications of the gaps today, solving the chicken/egg problem of how do we get the technology that we need in -- not only installed in equipment, but deployed on the grid through requirement standards, markets, mechanisms that will actually get these performance characteristics in the grid, get them deployed. And oh, by the way, we need to keep everyone whole in order to do that. We can't break, you know -- the need to actually have these elements still being profitable enough so that there's investment that wants to continue going forward in these projects. Otherwise, we're going to, to go back to your point, Howard, to have a resource adequacy issue on our hands.

So that's the very tight balance, keeping all of these things together, and recognizing that when OEMs build this equipment into the capabilities, they're not building that capability to their immediate customers necessarily, right? The generator owners have a very specific need to install equipment and make money by the revenue that is given simply selling power. And in order to do that, we need to make sure that you can optimize the output and stay online, don't get curtailed.

So that's the real genesis of the KPI that the developers really need to maintain, but oh, by the way, we also need to do all of these things to keep the grid stable. So that's a very different element, a very different aspect of how OEMs need to give that new technology to the grid companies, right, which are, you know, fundamentally the customers and the constituents of -- downstream of the generator owners.

So really, having that transfer function of technology development from OEMs all the way through to grid owners, operators, developers, that's a transfer function that is becoming more difficult to have, right? But also, we need to do things, to me, in a way today that demonstrates the capabilities of the new technology. And this is where we are with ESIG and the Global Power System Transformation Consortium, where we are looking at the capabilities of implementing grid-forming capabilities and making sure that we have good, sound, robust mechanisms in place to demonstrate those capabilities of grid forming on the grid, showing the benefits through demonstrations across the grid, but also showing that we're not going to have any unintended consequences of oscillations/interactions between the grid-forming technology to the grid-following technology, grid forming to other grid-forming resources, grid forming to synchronous.

And those are the types of things I think we need to invest in across the community, across OEMs, developers, system operators, utilities, regulators, and I really want to thank Mark for your participation in that, and, Mark Ahlstrom, for your leadership in the -- in the Council we have in order to institutionalize that. And then that feeds back into the integrated system planning work that we're doing with that as well. So we'd like to invite others that would like to know more about the ESIG and GPST activities about maybe what we can learn together and then have real foundational elements of what problems are we trying to solve and what regulatory impact do we want to have with, you know, understanding how to actually get the deployment of what we need.

MR. SHATTUCK: All right. Do we have time for questions. Yeah, I think we have a half hour for questions. We'll do the room and alternate with Slido.

Manish has already jumped up.

MR. PATEL: So this is not a question. I'm not even sure what I'm allowed to advocate or not as an EPRI employee. I'm still learning that.

(Laughter.)

MR. PATEL: So this is from -- this is from Manish Patel with couple of degrees in electrical engineering and some experience in industry. But I think -- seriously, I think some of this has been submitted as EPRI comments in writing with various drafts of the standard and all that.

But let's take a step back. Why are we here at the technical conference, right? So PRC-029, as written, allows exemption for legacy IBRs with hardware limitations, right? We don't know if that poses risk to the system or does not, yet to be determined. If it does pose a risk to the reliability of the system, then we are going to figure out a solution. It may be a solution that calls for, you know, retrofitting IBR. It may be a solution that is out on a transmission synchronous condenser, [inaudible 01:31:07], name it, right? We don't know yet.

The only reason we are talking about frequency Ride-through is for two reasons. One, PRC-029 curve, as proposed, are very stringent, and there is no exemption to legacy IBRs. I have worked in the industry for some time now. Number of times fault happens on the system are much more the number of times frequency deviates significantly. Even yesterday, I think Alex's presentation, none of the events caused the frequency to deviate by the magnitude and for the duration that we are talking about in PRC-029, right? But I was a protection engineer for living for some time, and, my god, lightning strikes and line trips, very common. Snake climb somewhere it doesn't need to climb, something trips, right? Voltage sags much more frequently than the frequency deviates from nominal.

So PRC-024 went through a revision just about couple of years ago, right? The intent at the time was to clarify that momentary cessation is not allowed. Even then that Standard Drafting Team did not think that we have to widen the frequency curves, right? Just two years ago, we went through 2800 exercise. I mentioned this. I was vice chair. We had no justification that IEEE 2800 frequency Ride-through curve is needed. Where it ended up coming from? IEEE 1547? Where it came, 1547? I think California Rule 21.

So when we were discussing frequency Ride-through, we were thinking about future grid. We don't know. We don't have studies. We talked to a lot of solar folks, and they said, yeah because they have to comply with 1547. They will have IBRs that will comply with, you know, frequency Ride-through curves. So then we talk to wind OEMs -- some of them are in the room -- and say, well, look, we would like to keep this simple. 1547 already uses this frequency Ride-through curves. Why can't we use it for transmission? After some conversation we landed on that. That sounds like a good idea. So now, two more years go by, and then PRC-029 comes along, and we have an even stringent, right?

I tell you, I think what Mark suggested earlier, if we hold all legacy IBRs to PRC-024 Ride-through and all new IBRs to IEEE 2800 Ride-through, then this gives the certainty -- I think Howard mentioned earlier -- this gives the certainty to system planners what equipment will be able to do based on in-service date. We have to decide what is legacy and what is not legacy. That's right. That's still -- that's still a question. But I think going forward, to me, it looks like all legacy IBRs, PRC-024, that standard was in effect anyway, right? Those plans are supposed to meet that anyhow. But one has -- even two years ago, the PRC-024 Standard Drafting Team said we need more than PRC-024 curves. IEEE 2800 landed on whatever because of 1547. I just don't see why we need to go one step further. So anyhow, I think that brings a lot of certainty.

Now, on a lighter note, IEEE 2800 and PRC-029, it's very difficult for a tongue to say. I think all the powerful people are in the room. Why don't we say IEEE 2800 and PRC 2900. Very easier, you know. Can we renumber the 029?

(Laughter.)

MR. PATEL: You know, just move zero from front to the back and add one more? It's free.

(Laughter.)

MR. AHLSTROM: Let me just say, I very much agree with you. I think PRC-024 for legacy assets is actually just fine, and, in fact, with IBRs, right, we're actually looking at it as a Ride-through standard, more stringent than, I say, it's viewed for conventional resources, right? So I agree. I agree. That would be the simplest thing that would save NERC, and all the compliance folks, and all of the OEMs, and all of the GOs a lot of time and effort that could be better used to put, you know, IEEE 2800 into the new generation of equipment more quickly and deploy it more quickly, right? And that was the argument I actually made in my written points.

You know, on the other hand, I think the exception process with 2800 is another good approach. It's more time consuming. It's going to slow down. It's going to create, to be honest, a lot more work for NERC, especially with the other non-IBR resources coming in, you know, under the new definitions of who's subject to compliance. That's going to be a lot of work for NERC, I think, you know. So I think you could simplify it by just sticking with PRC-024, but I'm perfectly fine with 2800 plus an exemption process as well.

MR. GUGEL: Yeah, the only thing that I would add to that, and this point was brought up yesterday, is that 024 is not a Ride-through standard. 024 just does the set points. And so, you know, if you need requirements for Ride-through, you really do have to go a little bit different.

MR. AHLSTROM: My point Howard, I think the IBR community actually ends up interpreting it as a performance Ride-through standard, right, because with electronics, what's the difference between protection equipment and IBR is when you really get down to it, right? So all I'm saying is if you applied it as a Ride-through standard to IBR, I think the IBR community would be fine with that, and it would actually would exceed what you're doing with conventionals.

MR. GUGEL: The only -- man, I hate to put on my compliance hat.

(Laughter.)

MR. GUGEL: The only issue that we have there is you've really got two communities in the IBR area. You've got the one that is traditional generator owner/operators that are with traditional utilities and understand NERC standards, and do that application. You've also got now into this organization, financial institutions that would just look at the letter of the law as opposed to what was actually intent behind that. And I think the issue for us is going to become enforcing PRC-024 as a Ride-through standard when it doesn't necessarily state that in the standard, but it just says that your set points and your protection need to be at a certain level.

So I agree that the curves for -- as we start to look at things and start to interpret how legacy and future things should go in, I think that, traditionally, most folks have considered PRC-024 curves where they want the operating limits to be and the constraints to be on there, other than the fact that there were some that interpreted that curve that if it was outside, it was a must trip as opposed to can, you know. And I think we've gotten that misunderstanding straightened out with most folks.

I do think there's still that learning curve, and, potentially, the concern that may be out there that folks that haven't traditionally been in the NERC realm would not interpret PRC-024, the letter of that, to be a performance standard, but instead just a setting standard.

MR. AHLSTROM: Agreed. But I mean, couldn't you put the PRC-024 in as the legacy must comply with PRC-024 as compliance -- as a Ride-through standard into PRC-029?

MR. GUGEL: Yeah, I think that's potentially a path forward, at least looking for some of those curves and when you're talking about exemptions. I do think there's a potential there, yeah.

MR. YEUNG: Okay. We'll take the question from the room.

MR. KOERBER: Arne Koerber, GE Vernova Wind. The topic of this panel discussion was exemptions. Yesterday, we mentioned a few things that make it hard for us to sign up for not being able to do something. And to embark on a product development, even if the product is retrofitted, with the sole intent of finding a roadblock where we can't do it.

In the discussion today, we went back to a lot of -- we discussed a lot of, oh, we need documentation that allows a -- I don't know -- I'll call it a semi-public design review of why we can't do something, and this is -- this is a real question. I'm not saying this to make a point. Any thoughts from this panel on how you would structure an exemption process that doesn't rely on OEM saying we cannot do this? Like, how would -- how would you structure an exemption process, again, that doesn't -- that doesn't go back to proving something can't be done, which we have concerns with.

MR. GUGEL: I'll start with this, and I think some others might be able to lean in on this, too. You know, we struggled through this same issue when we started talking about cold weather and design parameters for units as they get down to extreme temperatures, whether they're low or high. And basically, what it came down to was producing design parameters, what was the unit designed for and having that there. I think if you can pull out that information and say, look, this unit wasn't designed to Ride-through a particular frequency, wasn't designed to Ride-through a particular voltage because this was the specifications for that unit at the time, that would be adequate documentation as opposed to trying to prove a negative. And I'm just speaking for Howard at this point. But I think having the design parameters and that information to lean on is probably the best documentation rather than some sort of a -- of a test that says, hey, look, I tripped, so I know that it can't do that.

MR. KOERBER: Just to make sure I understood correctly. So you would be saying all maximization always goes up to the originally-stated capability from potentially many years ago, but there would be no intent to go beyond that?

MR. GUGEL: I would say that, yes, that basically -- well, if you did modification to the plant that you knew would take it in a different way, that you'd have that documentation also, but, you know, if a -- if a plant wasn't designed to do X, you can't expect it to perform X today.

MR. ROGERS: Now, that last point you got to is kind of what I was going to get to as well, and I think that that would be very important in the documentation process, the exemption process, is not trying to prove the negative. It's stating the positive and it's clearly communicating the positive, and there may be a whole lot of unknowns, especially when I'm talking about, you know, some of the fleets that -- you know, that OG&E owns, the stuff was put in the ground, again like 2005. It was designed in 2000, or, you know, probably '98, '99 is when the design process on a lot of that started. We don't know these things. We wouldn't be able to state these things. And even if we did some type of testing on one of these units, one, may fry the unit, that's bad, what do you do, hook it up to the next one and try the next unit? That sounds like a bad idea.

Or if you're able to perform some type of simulation, say you do get enough parameters to do something, is that representative of my fleet? You know, these things have been in the ground for 20 years, one of them's been on top of a hill in Western Oklahoma, one's been on the bottom of a hill. The one's been in the shadow of the tower, one's not, you know, I mean, and degradation of electrical components over time is a very real thing. And I think that has to be very clearly communicated, and I'm glad that was brought up so this can go on the record for the Standards Committee and everyone else who's drafting this to understand.

It's very important that we don't try to prove the negative with this exemption process. We state the positive. We state what we can do and nothing more. If there are things maybe that the standard talks about that we're not capable of doing, address those specifically as unknowns, you know. Don't leave the fill blank, right? State, you know, this is an unknown. This was not designed with this parameter or with this capability in mind. Does that mean it can't do it? No. That means we don't know what it can do. And I think being -- stating that and being very clear about that is very important for the exemption process, one, to be something that's workable, but also be -- provide the maximum value. Thanks.

MR. YEUNG: Thanks. We'll go online.

MS. CASUSCELLI: All right Thank you. Yeah, we have a number of questions online. So the first one is, if the protection at inverter terminals does not comply, could the GO submit an exception without dynamic analysis. Asking because of effort/availability of models.

MR. GUGEL: I want to make sure that I understand. Are you talking -- are they talking about the protection -- the protection system of the units? Are they talking about the design? I'm not sure that I understand. If you're -- if you're talking specifically about the protection system, I would struggle figuring out how a protection system couldn't be modified for that specifically if you're -- if you're just talking about that. If you're talking about how the unit actually performs, that's a different conversation.

MS. SHAH: I can probably add some color to this. This coming from one of my SMEs. What we are trying to understand is can we skip the dynamic model effort, especially for operational sites where these models are not available to us easily. That's pretty much what we are trying to understand, that can the EMT modeling part, if we don't have the models, can we skip that when we are submitting exemptions, or we are seeking exemptions on some of those models, which we don't have, are not available from the OEMs.

MR. GUGEL: Yeah, I'd have to further understand the requirement for an EMT model in that -- in the exemption, so no. Is that requirement in there for the voltage side for the exemptions?

MS. SHAH: Yeah, frequency,

MR. GUGEL: And if it's not, I'm not sure -- nobody's talked at this point about -- at least I haven't heard anything yet -- about specifics about how that exemption would be designed for the frequency side. So, I mean, it's a good question, but nobody at this point has proposed a requirement or not a requirement for EMT studies.

MR. PATEL: May I -- may I chime in real quick?

MR. GUGEL: Yes.

MR. PATEL: So I think this question is more appropriate for voltage Ride-through capability than frequency, right. So capability frequency shouldn't change a whole lot between the terminals of inverter or wind turbine generator on the high side of the plant.

For voltage, there is actually a paper that is up for approval by RSTC, written by NERC System Protection and Control Working Group, that actually shows one method to use instead of EMT model to make sure your voltage settings at inverted terminals. And it does not -- does not require EMT. You can do basic power flow. It is a bit conservative and shows, you know, one way to evaluate your voltage settings compared to the requirements of the POM.

MR. SCHMIDT GRAU: And also to add, I think it's also important that the OEMs take accountability and provide attestations on that because certain equipment, you can maybe do it for voltage without any studies. But I also know from Vestas product, you will have to do some kind of studies because of so many dynamic factors. And you can have protection settings on voltage that is set way below the PRC-024 or 029 curves in your equipment and still compliant -- comply at plant level.

MR. GUGEL: Yeah. I think a positive that comes out of everything that we've talked about for the exceptions process is it forces communication. I mean, you're now basically enforcing a communication between the OEMs, the generator owners, and the transmission side to make sure everybody understands the parameters on that as opposed to maybe assuming things that we've done in the past.

MR. SHATTUCK: And just to maybe add to Howard's, you know, through the alert process, we've had quite a bit of difficulty getting the extent of condition of what's out there. And an exemption process like this, again, forces it so then we know what's out there, right? And it's documented and through a really formal process, so it is a benefit. Let's maybe do one more online. We did two in a row? Sorry. You were kind of both. We'll do one more online.

MS. CASUSCELLI: All right. I'm going to ask this one. What level of time and effort might be saved by adopting the consensus developed under IEEE 2800 rather than developing new requirements under PRC-029?

MR. GUGEL: I think that's something that the Standards Committee and the Drafting Team will have to take under advisement as they go forward, but at least at this point, they've had a couple of rounds of this going out. I think the conversations that we've had yesterday and today are providing some clarity in particular areas that have been raised for some of the questions. And so I think all of this in context is going to be something that would be helpful for them.

MR. YEUNG: Let me just -- as a moderator, that was one of our concerns, you know, trying to get some clarity because The Drafting Team will have to -- well, the Standards Committee will have to, you know, make that assessment. I think Mark has some good data, you know, comparative data. Hopefully we can get some more in our process, but that's absolutely something we're going be looking at, you know. What are the benefits of using 2800 versus 029?

MS. SHAH: Thank you. Ruchi Shah from AES Clean Energy. First of all, I want to start with some of the suggestions that were given today about PRC-029, what possibly can be done as a resolution. And in my opinion, what Manish suggested, Mark suggested are great suggestions, something that I'd highly recommend considering as an option to move forward with the standard.

A consideration or a question from my end is, as we are discussing how exemptions should be provided, a question that we have is, do we have the manpower from OEM perspective, utilities' or entities' perspective to support these exemption efforts as well, and where we draw the line with legacy. I think at this point in time, as we hear yesterday from the OEMs, if 95 percent of the OEMs cannot meet PRC-029, isn't everything right now considered legacy because we really can't meet PRC-029 with the existing technology? So that's my biggest question. Do we have the manpower? Can we consider everything legacy until we get to a technology point for frequency Ride-through?

MR. AHLSTROM: I would -- I would just say that working with the people in NextEra, who do a great job of maintaining a huge fleet, the answer is no. Even if NextEra does not have the manpower to actually do this, we'll find a way to get done what has to be done as we always do. But yeah, the pool of people that really are available to do this, the consultants that are needed to provide the models, you know, the plant models side is very limited. You know, all these things are in very short supply, you know. So that's going to consume -- compliance with this will consume a huge amount of the resources on the OEM plant operations side for at least two years, you know, even if it's software only, right, on the best case.

So it's a big lift, but, you know, I do think that that's what has to be done. You know, we'll comply. We'll find a way to do it. But it -- I am concerned that it pulls a lot of the OEM engineering resources away from speeding up the build-your-way-past-this-with-better-equipment side, and it will delay the availability of some of the next generation of the technologies that we most want and would be used for any of the re-power's replacements, you know, to get us to a more compliant fleet more quickly. So I think we have to weigh that, what's the right balance between how much resource do we put into the old installed fleet versus accelerate the new fleet, right?

MR. GUGEL: I would provide a -- I don't want to put words in your mark -- in your mouth, Mark, but I think I'd provide a bit of a caveat. That's assuming that you use the existing curves that are provided in

PRC-029. Maybe a question back to you would be, if instead the legacy stuff looked more like PRC-024, would you have as much of a manpower issue --

MR. AHLSTROM: No.

MR. GUGEL: -- of providing that information?

MR. AHLSTROM: Oh, no. As I -- as I have documented in my comments here, you know, we have 9,000 turbines, four OEMs for the current PRC-029 draft. We have about 6,000 turbines, two OEMs if we go to 2800. And we have virtually nothing if we, say, comply with PRC-024. We got 200 megawatts. I mean, it's one plant, one OEM. It's nothing. So I think that' it's compliant.

MR. GUGEL: The caveat there is, it depends, right? Whatever curve you choose on that is going to -- is going to basically determine the amount of manpower that'd be required on the OEM side and on the generator owner side to provide that documentation.

MS. SHAH: And I agree with that. I think my question was more, if we go with the existing PRC-029 and we have to work towards exemptions, upgrades, that's where I would speak for Clean Energy as well.

We are concerned about having the skillsets and the manpower to support this, while we are also at a future looking -- forward looking, how can we ensure this risk is mitigated and we are reliable.

MR. MACDOWELL: Yeah, and I think, you know, well said, Mark. I think that the biggest impact on evaluating the capabilities on the GO and the OEM, but there's also, again, with my ESIG hat on, there's also a bigger, broader impact on capability even with the system operators and utilities that have to reevaluate this as well. So there's -- it's not only on the GOs and OEMs, but it's everyone that has to reevaluate that capability that needs to go through the interconnection process again, or even determine whether there's a material change, right?

So I think across the board, and I -- from a compliance point of view at NERC, too, there's going to be some sort of impact. So I think whatever can be done to look at what is existing on the ground that's doing well enough to support reliability, not making any changes, really relieves a lot of the stress on the entire ecosystem that we're all fighting for the right resources to be able to do this, whether it be OEMs, developers, NERC, system operators. The pool of resources capable of doing this type of work is very small, right, and I think that that's the practical reality of the issue that we're up against is time/cost versus resources to get this stuff done.

MR. GUGEL: Yeah, and I think the good focus for maybe the team that would be developing the next draft on this is, you know, the idea is we want to establish the bar for those units going forward, and then let's figure out what should be done with the legacy. And I'm going to -- I'm going to use air quotes there because I already talked about the issues. But again, what should be done with what's in the ground right now, and let's make sure that at least from the line we draw forward, that we have an expectation that plants behave a certain way.

MS. SHAH: And that leads me to my next question about risk prioritization. As we are trying to balance between what we have, the technology challenges and the upgrades or retrofits that we are considering for existing resources, for a ban that is using a scenario as we all learn through the conversations in these two days, that we are not sure if there are any studies to back it up. So should we focus on our efforts to really comply with that ban, or should we really focus on future forward-looking technology where we can invest our efforts and for a better, reliable grid condition, and really use the data from the other performance standards that we are also moving forward with, use that data, understand how this will impact the grid, get more factual data? So something that I'd really recommend the team to consider as we look towards redrafting PRC-029, focus on the bans, consider the exemptions for that.

And one last point that I want to recommend to the team is, as we consider the exemptions, and putting my compliance hat on, documentation for the exemptions, we do have OEMs that are not in business anymore. So getting documentation to even submit the exemptions will be a challenge if we can carve out something in the technical rationale in the standard. I know with -- it's hard to put too many caveats in the standard when we are writing it, but somewhere if we can document this, that there could be a possibility. We may not be able to provide a lot of data to support the exemption. What we know is what we know, and that's all. We have no one to collaborate, communicate with to get additional details. That's all.

MR. GUGEL: Yeah. Thank you. Yeah, I'm not sure how much of that would be able to be codified within the standard, and I'm not sure how much comfort you're going to get from my saying "trust me." But we understand that this is an issue, and I know that as we look at compliance across the ERO, that we're going to be looking at it from a risk-based lens. So, you know, OEMs that are -- that are out of business and you can't get the documentation is one thing, but hopefully at least you have the original design parameters for the plant itself, and that would provide a lot, I think, of the information going forward.

MS. SHAH: Thank you.

MR. SHATTUCK: Thanks, and we'll do one last question from Slido.

MS. CASUSCELLI: Thank you. How about taking all considerations from yesterday to get a set of classes/types of entities/IBRs, each assigned a compliance threshold, incentivizing upgrading?

MR. GUGEL: That sounds like an accounting nightmare.

(Laughter.)

MR. GUGEL: So, you know, we tried something similar to this in other standards, and I know there are folks online that maybe haven't been as participatory in the standards development process as others have. We have looked at, in some of our protection standards and some of our maintenance standards, doing a percentage increase over a year as to how things are complied. And frankly, it becomes -- it becomes difficult to demonstrate X percentage of your fleet/pieces of equipment when that number calculates out to a decimal point, and it just -- it just drives me nuts, and I'm sure it drives a lot of folks nuts on that.

Instead, in my opinion, it's better to have that line in the sand that says, look, everything after this particular point needs to be at X, and prior to that, we'll be looking at, you know, the exemptions, the facts and circumstances around that -- those units, and making sure that it fits into the parameters that are described in the standard itself. So I mean, great idea. Sounds good. It's the implementation and the practicality of those that it becomes the devil in the details.

MR. SHATTUCK: Thanks. Any other thoughts to close this out? We're at the correct time, and thanks, everyone for participating with our panel, but any closing thoughts from anyone before we all get off the stage here?

MR. YEUNG: I'm sorry. I think we heard some really good ideas, particularly the last comment about the exemptions and information. I think that's going to be real key in helping the Standards Committee determine what the exemption process looks like, so I appreciate that. Are we taking one more question?

MR. DAHAL: I would like to make some comment. I'm Samir from Gamesa. When we responded to your questionnaires about can you meet PRC-029 as it is written, right, no. Can you meet -- what about IEEE 2800? We operated with the assumption that those curves are just curve setting. We did not dive into the performance specification like ROCOF, multiple excursion. So if you were to consider that, no, we cannot meet IEEE 2800. So your response, as Mark said, would definitely vary significantly. So that's something for the committee to take into account, right? We're just talking about those protection points and not the performance. That's the point number one.

Point number two on repowers, like I kind of mentioned yesterday, there are different type of repowers. So committee or somebody needs to take into account is the repower mainly mechanical one to increase the efficiency, or it's an electrical one where we swap out the converters. So without that distinction, it will become very convoluted on what to comply with, you know, what standard to comply with.

Third point is on software update, model update. Like, so if we said, okay, we can comply with -- for some of the legacy units, depending on the definition, we can expand the protection curve. We know we can do it, but if we have to provide models beforehand, that will delay the implementation process because, like I mentioned, model might not have been updated, depending on what -- how back in the past we want to go. Do you want the advantage right now, or are you willing to wait couple of years for the model to get updated? And it's not just an OEM. You know, we do source our converter from other OEM that we need to reach out and ask them to give us the model that will comply with today's computational lead, right?

And then last point that I would like to bring up in the prioritization, like Mark mentioned, like he himself has 10 converter models, right? So we have certain converters on the field that we have in larger quantity than the other, right? So if there is a guidance given, either based on the number of internal capacity, or the reason that you guys from your experience say, okay, this reason is more vulnerable, so we can focus on this reason, make this a prioritize, or based on the number, then that would help us out to allocate our resources. Otherwise, learning from NOGRR, we are getting all OEM, all the operators reaching out at the same time asking for the capability and the model update, and we have to -- we have no way to prioritize. So they would go back on the queue, and then we won't be able to, you know, help them as -- in the most beneficial way.

So those are my comments and I want -- I want Drafting Committee and the NOGRR to take -- RTOs to take those into consideration.

MR. SHATTUCK: Thank you very much.

MR. YEUNG: Okay. So I think we can close this panel. Todd, you want to make some comments?

MR. BENNETT: No, Charles, I don't think I have anything else additional, other than to thank the panel. This was a wonderful panel, a lot of great technical insights here. Give them a round of applause for all their efforts here today.

(Applause.)

MR. BENNETT: And I'm showing 11:05. Let's reconvene at 11:15. Thank you.

(Break.)

MR. BENNETT: -- portion of the technical conference. So this is last thing between us and lunch here, and that's not a please hurry up. That's a I'm excited to hear about what you have to say.

So outlining objectives of a Ride-through definition. I believe we have a couple Drafting Team members here to come speak to us about this, but this states specifically Joel. So, Joel, take it away.

MR. ANTHES: Yes. Good morning still, and I was just telling Husam that this is the perfect time for us to present because hopefully everybody will be hungry and not want to ask us a lot of questions after our presentation.

(Laughter.)

MR. ANTHES: But my name is Joel Anthes. I'm a system protection engineer with a Pacific Gas and Electric Company. I'm from California. I'm a member of the Drafting Team for 2020-02 for PRC-029, and I have Husam Al-Hadidi with me, who's the co-chair of the Drafting Team.

So I was reading through the description of what I'm supposed to present on, and it says, "a thorough examination of the usage of the term, 'Ride-through,' within NERC reports, IEEE, currently active Ride-through, reliability standards, and other industry usage of the term." So just to be upfront with you, I don't think we could do that in 030 minutes, and I would not be qualified to lead that discussion anyway. My middle name is not "Ride-through."

(Laughter.)

MR. ANTHES: But what I would like to give you is an overview, the history of the Drafting Team's thought process for how we got from beginning to draft to at least our Ballot Three, our latest proposed IBR Ride-through definition.

So if we could go forward a slide please.

So I reread the SAR, and the SAR directed us to consider defining the term "Ride-through" as necessary. Now, in our first ballot, we actually took the approach of not defining Ride-through. Our intention, as I understand it, was to really define "Ride-through" within the requirements of the standard itself, rather than to give a comprehensive definition of "Ride-through." But after meeting with the PRC-030 Drafting Team, which defines the triggers for when you investigate Ride-through performance within 029, it was a specific request from them that we go ahead and define the term, "Ride-through, "so that they could index, so to speak, into the requirements of our standard and reference it within their own. So draft two, we began by putting our first attempt at a Ride-through definition.

If you could go to the next slide, please.

So some of the goals that governed our thought process on this was we wanted to have a definition that could be included in the NERC glossary of terms. We didn't want to unnecessarily tie it specifically to our standard, and then we wanted other standards to be able to refer to that definition when either indexing into our requirements or referring to our requirements. So those were just a couple of goals that we tried to keep in mind while we were drafting it.

Next slide, please.

So some of our goals were not -- we didn't want to create additional performance requirements just by defining "Ride-through." We wanted to keep the performance requirements of Ride-through within the actual requirements of PRC-029. So something to keep in mind when we look at how we kind of went through and the evolution of our proposed definition is it wasn't intended to be an all-encompassing performance definition, only a definition, very bare bones definition, so to speak, of "Ride-through."

Next slide, please.

So our first draft, I'm just going to read it: "remaining connected" -- so this is going to be the definition of "Ride-through": remaining connected, synchronized with the transmission system, and continuing to operate in response to system conditions through the time frame of a system disturbance." And then after reading through many pages of industry comments from draft two, we ended up incorporating those comments and tweaking the definition for draft three, which is the latest that we've proposed. And that is a definition of "Ride-through": the entire plant facility remaining connected to the bulk power system and continuing in its entirety to operate through system disturbances.

So a couple of things. We ended up removing "due to industry comments were synchronized with" from draft two, and "in response to system conditions." So there was some concern whether it was justified or not. There was some concern with us using -- applying the term and the concept, "synchronized," to inverter-based generation. And there were some who felt that it was not appropriate to use the term, "synchronized," because we weren't doing a standard for synchronous machines, and we went ahead and removed that term.

And "in response to system conditions," that had generated some comment, as I recall, of what are those conditions, what is appropriate response, all of which we weren't trying to define merely through a Ride-through definition. And then we ended up adding the concept of "entire" and "in its entirety" because there was real specific concern, as I recall, from one stakeholder, in particular, that if we -- if we didn't clarify that, then generator owners and operators may consider partial tripping of inverters when considering the R3 requirements for returning to pre-disturbance, real power levels. And so this was an attempt to clarify that. It wasn't -- I'll just leave it at that. It was an attempt to clarify that you couldn't subtract partial tripping when you were required to come back to your pre-disturbance available power after a system disturbance. And then we replaced "transmission system" with "bulk power system," and I think the key there is that we were trying to deliberately exclude distribution-level IBRs, and bulk power system would be exclusive of distribution -- solely distribution-connected IDRs.

Okay. Next slide, please.

So another thing we attempted to do was to use, wherever possible, NERC glossary of terms, so "bulk power system" is clearly defined. It excludes the local distribution of electric energy. "Disturbance" is clearly defined. It includes abnormal system conditions, perturbations, and frequency deviations.

Next slide, please.

So one of the things that we referenced, there's this most admirable definition from IEEE 2800, and we drew from the concept of this. I'm going to read it to you. It is, "ability to withstand voltage or frequency disturbances inside defined limits and continue as specified." So I think the main reasons that we didn't directly use this definition is some of the nuances of the language, "ability to withstand," for instance, may not necessarily mean remaining connected to the transmission system. So instead of -- instead of "ability to withstand," we used "remaining connected." "Inside defined limits," we felt that that may unnecessarily tie it to a specific standard. We were attempting to make it a more standalone definition, and similarly with "as specified." Again, that's more of like a standards requirement, a performance requirement you have to then perhaps specify along with your definition of "Ride-through." So those were at least our thought process for avoiding some of those things. That's why we didn't directly use the IEEE definition.

Next slide, please.

So in response to Ballot Three and Ballot Two, we went through, looked at the comments. Industry proposed 11 different definitions of "Ride-through," and I read through all of them again last night. And I had a headache, and so I thought I'd like to share that with you.

(Laughter.)

MR. ANTHES: So I'm not going to -- I'm not going to comment on -- you know, rebut against each one. I think they all have some value in the way industry was thinking, but in general, three things that I saw where they kind of deviated from ours. Some of it was just word order preference. You know, maybe they were trying to say the same thing, but they didn't like the way we worded it. And then two other things that were more significant, at least in my mind, were adding in the concept of in -- adding in the concept to the definition of "Ride-through," that your response needs to be in support of grid reliability, and then also maybe adding back in the concept of your response needs to be as specified within the standard itself. So for number one here, I think that one kind of merged aspects of IEEE 2800's definition with ours.

If we could go to the next page.

This one here, it seemed to kind of add back in the concept of operation in support of grid reliability. So it says, "Facilities, including all individual dispersed power-producing resources, remaining connected to the electric system, and continuing to operate in a manner that supports grid reliability throughout a system disturbance, including the period of recovery back to a normal operating condition." So again, these are draft comments that were proposed within the industry, comments to the Drafting Team, suggestions from industry for tweaking the Ride-through definition.

Next slide.

So this one seemed to want to remove, at least in part, the concept of the plant operating in its entirety, Riding-through in its entirety. So "Remaining connected, synchronized with the transmission system, and continuing to operate by delivering power in response to system conditions through the time frame of a system disturbance." The next one, 5, "The entire plant remaining connected to the bulk power system and continuing to operate the system disturbances," very similar, I think, in principle to what we proposed.

Next slide.

So 6 and 7 here. "The plant facility remaining connected to the bulk power system and continuing to operate through system disturbances as defined within applicable reliability standards." So that one kind of adds back in the concept of within defined limits of the standards within specific operating limits. Seven, "the entire plant facility remaining connected to the bulk power system and continuing in its entirety to operate as specified through" -- oh, I can move on to 8.

So 8 here: "The entire plant facility remaining connected and continuing to operate through the duration of frequency and voltage disturbances, in its entirety, from the start to the return to pre-disturbance conditions," so it basically removed the reference to the bulk power system. And then 9: "The entire plant facility remaining connected to the bulk power system and continuing, in its entirety, to operate as specified through system disturbances inside defined limits." So that one kind of added back in the concept of defined limits as specified within a standard.

Next slide.

I think is our last -- second to the last. "The entire plant facility, including its dispersed power-producing inverters, remaining connected to the electric system and continuing, in its entirety, to operate in a manner that supports grid reliability through a system disturbance, including the period of recovery back to a normal operating condition." So to me, that one also kind of added in the concept of you need to operate in support of grid reliability, maybe more of a system-level definition.

Last slide, number 11, "The plant facility shall remain connected and in service, maintaining the pre-disturbance equipment configuration in operation throughout the entirety of the system disturbance and recovery." So this one, again, kind of removed the concept of the entire plant operating.

So I think the story in my mind of this is that you could probably put a hundred different people in a room and you'd get 120 different definitions. And there's -- I'm not minimizing the input and some of the concerns and some of the things that industry has highlighted, but there -- you know, at least maybe it gives you a feel for what we went through in reviewing all of the industry comments and trying to come up with something simple that met the goals. So I think that's it for -- do we have Q and A now? Okay. Hopefully you're all hungry.

(Laughter.)

MR. VENKITANARAYANAN: Nath Venkit from GE Vernova. Thank you for going through the background and all the different definitions. I have a comment on the "in its entirety part," and the way I read it is if you have a wind farm with about -- with a hundred turbines, and if you have an event and one of them trips, one out of a hundred trips, then the whole plant is not compliant. Now, as an OEM, I would like to say that this may be impractical. The reason is you can have -- let me give you some examples. You could have a turbine that is losing its wind resource and is in the process of gracefully shutting down. So its rotor RPM has gone below a certain threshold, and then it's counting down to shut down, and that process is a graceful shutdown.

Now, during this period, if you have a Ride-through event, then you're not going to gracefully shut down. You're going to shut down, okay? And then it's going to take a few minutes before the turbine comes back up. That's one example. There could be other examples where turbines are -- an individual turbine may be seeing a combination of conditions -- wind gusts, turbulence, whole bunch of other things -- that is causing it to operate in what I would summarize as survival mode, right? So it's over speeding, and it's trying to control that speed. And the whole objective is to not shut down that turbine but to allow it to manage that and come out of that survival mode into normal operating mode. But if you are in that kind of a survival mode and an event happens, that turbine is very likely to trip.

So for all these reasons, if you look at IEEE 2800, it says that after a fault, when you recover, it is sufficient if you recover to 90 percent of available power because it's possible that some of the inverter-based units will -- would, would trip for some of these conditions.

MR. ANTHES: Yeah.

MR. VENKITANARAYANAN: So in my mind, requiring that not even a single inverter-based unit under whatever conditions it's operating in -- losing its wind resource, gracefully shutting down, operating in survival mode -- under any of these conditions, if it should be able to recover, that can happen only in theory and not impact this.

MR. ANTHES: So if I could interrupt you because I'm going to forget the first part of your answer if you go too much further, but so my understanding is it was not our intention to make a standard that was -- absolutely prohibited any tripping of a unit. So as I understand it, PRC-030, our companion standard, is going to define the triggers for when you investigate PRC-029. So I think as they passed, it's a 10-percent reduction in real power, or 20 megawatts is, I think, what they have in there. So if you had a 10-percent reduction in real power or a trip of 20 megawatts, or, I think, if it's your transmission planner operator requests an investigation. So that's my understanding and how I've tried to explain it to my company is that that is the trigger for then assessing your compliance with PRC-029.

So I don't think it was our intention in putting in the concept of its entirety to absolutely prohibit any tripping because that doesn't seem reasonable. However, it came -- for better or worse. So the reason it wound up in there is there were specific entities concerned that you could have a disturbance on the event. Twenty percent of your inverters might trip. You're expected to come back to your available active power after the disturbance is cleared. So their concern was, you know, unless we say something about in its entirety, they might go, okay, well, my available power is the 80 percent I have left on, so I'm totally compliant, but they might have lost a significant number of inverters due to the disturbance. So our intention with this, and maybe it wasn't clear enough. I'm thinking based on how many comments we've had like yours, it probably wasn't clear enough. But our intention wasn't to, I believe, absolutely prohibit any tripping, but it was to disallow when you return to pre-disturbance, subtracting things that tripped out from your available active power.

MR. VENKITANARAYANAN: Just to add to that to be very clear, a clarification, we don't look at the individual unit, so really, IBR unit was not part of our scope. So really if you have hundreds of IBR unit and you are able to go to -- recover to pre-disturbance megawatt, even if you lose five, 10, 15, as long as you could maintain the pre-level disturbance after the event, you are in compliance with our standard. And we added flexibility that if the TB or RC or whoever want to give you a different level to say, no, recover to 90 percent, 95 percent, we couldn't. We said this is going to be system dependent, and we lifted an open flexibility on the standard. So you are not -- there is no requirement for every IBR. You need to recover -- the plant need to recover the pre-disturbance value. So your concern if it's one unit and it's not going to impact the plant --

(Cross talking.)

MR. AL-HADIDI: It will impact.

MR. VENKITANARAYANAN: -- then you have to bring it -- the GO owner has to bring it back to their TB or RC to see does that really need to be exempt from that or how that need to read that. But for now, the standard, it's saying that if you're able to recover from the power, you have no issue. If you don't, there's a TPRC flexibility to provide a different level other than a hundred percent.

MR. AL-HADIDI: See, I don't see how that can happen. If you have a hundred turbines, each of them producing two megawatts, and one of them trips, okay, you're not going to recover back to 200 megawatts. You're going to recover 298 megawatts. So, again, I mean I --

MR. VENKITANARAYANAN: As I said, this is reliability question. That's why we couldn't determine this -- the number, which is it 95 percent? Is it 90? What's the value? We say the standards require you to -- require you to recover back, and the TPRC, based on their system, they can provide any criteria as needed to support their system. So flexibility is there, so there is flexibility in the standards.

MR. AL-HADIDI: Again, I mean, I don't want to argue. I think reliability is important, but having a practical solution is also important. So I think we have to draw a line that you can't have 20 percent of the units tripping, but it's okay if you have two or three units stripping. So somewhere, you know, there should be an element for that. Thank you.

MR. ANTHES: So maybe to your, because I think you had two points in there. One thing that came to mind as you were discussing the scenario of a wind turbine ramping down due to, you know, maybe wind has ceased, and in requirement R3, we do specifically say you have to return to available active power. So if you have -- if your available active power is different because you have lost wind or because cloud cover has affected your solar production, we intended to account for that in returning to available active power. But the concept in its entirety was to not allow you to trip a whole bunch of stuff off and go, well, I only had available the stuff that didn't trip, if that makes sense.

(Off mic comment.)

MR. VENKITANARAYANAN: Yeah. Thank you.

MS. CASUSCELLI: Okay. I'll ask one of the online questions. Has the Drafting Team considered adding specific language to align the language clearly with PRC-030/defined the levels similarly?

MR. AL-HADIDI: BRCT? I don't remember.

Actually, we create this definition to align with BRCT, so that was the intent of adding the definition to the standard, so really, it was mainly -- just really the main intent. So I thought we achieved that objective.

MR. GUGEL: Hey. Howard Gugel, NERC. There was a phrase that showed up in several of the definitions that was triggering for me, so I just want to make sure that you have a lens on for it, and it was "remained connected." And sometimes when you start talking about momentary cessation, there's no mechanical disconnect that occurs there, but it's an electronic change. So somehow, as you're looking at this idea of Ride-through, make sure that you take into account it's not just a mechanical change that could occur there, but also any sort of a momentary cessation that might be taken into account.

MR. AL-HADIDI: I thought we did for that. We said to "continue exchange current," so we said it's not -- and I believe that's the reason. But reason where we did not add to support the system, it was a reason for, like, for R3. We are not required any performance requirement from the IBR. So we -- if we said that -- if we are now saying you need to support the system, and now there'll be -- it's very hard now to say if you Ride-through or not because if you do not produce enough or change your megawatt to support the system, it could be your Ride-through, but they're not compliant because you did not meet the definition. So that's the reason sometimes we did not adapt some of the suggested language from some of the stakeholder because we felt that it may add more compliance requirement, which we try to avoid to some level.

MR. ANTHES: Yeah, and I did read through the SAR again. The concept and the specific terms of "remain connected" were used extensively. And I -- you know, for better or worse, I think a lot of people view "remain connected" as what it's intended to mean, which is you Ride-through, you continue to exchange current, you remain connected.

MS. CASUSCELLI: Okay. We've got more online questions. As stated by the panelist from the Drafting Team, it's not reasonable to prevent all tripping. However, this is not how the draft is written. Should this be explicit?

MR. ANTHES: Well, again, as I see it, we have three reliability standards. We have PRC-028 for the data acquisition and monitoring, we have PRC-030 for the event triggers, and then we have PRC-029 for the performance. So as I understand it, the triggers for when you evaluate PRC-029 compliance and performance come from PRC-030, and the data that's necessary to evaluate that is recorded based on your recording equipment in PRC-028. You know, maybe PRC-030 and PRC-029 should've been one standard, but they're not, so without reduplicating all of the requirements, I think we tried to compromise and go, okay, these are event triggers in PRC-030.

MR. PATEL: So, Joel, we have talked offline, but for everyone's benefit, I think we keep referring that PRC-029 and PRC-030 are connected. That is true, but remember, PRC-030 -- so practicality is that we cannot evaluate each and every Ride-through operation. It's just very difficult. We have other jobs to do. So the way I see this is that PRC-030 has a criteria. If it's met, then you go investigate what happened. That doesn't mean that the plant is not in compliance or in compliance with the PRC-029. If you reduce output by 10 percent or 20 megawatt over 4 second -- I think those are the numbers in PRC-030 -- all that means is you go investigate what happened. The answer could be plant did not perform as expected. The answer could be the plant performed as expected. If it did not perform as expected, out of compliance with PRC-029. I think that's where even Nath's point came in, that if one wind turbine tripped offline out of a hundred, you could be out of compliance.

MR. AL-HADIDI: Yeah, but you have to remember we do not quantify the number because you could have now 2 giga -- 2 giga or 5 giga plant, and now the 20 percent, the 10 percent becomes significant amount of megawatt.

MR. PATEL: Yeah.

MR. AL-HADIDI: We leave that flexibility, and we were not -- there was a huge push even for us to keep that flexibility to say don't -- multiple people, you won't to recover back to the hundred percent. We say it's system dependent, and only -- we found the best compromise way to deal with it is to leave it --

MR. PATEL: Yeah.

MR. AL-HADIDI: -- leave that open for the TPRC based on their system need, to keep that exemption because the standard said, yes, they can specify different value than the hundred because we agreed sometime hundred is unachievable target.

MR. PATEL: I'm not debating that. I think you debated that enough with Nath. What I'm trying to say is that there is a criteria in PRC-030, and that determines if you're in compliance or not. It's a -- it's a -- it's a wrong understanding.

MR. AL-HADIDI: No, no, I agree.

MR. PATEL: The way the standard is written, PRC-030 criteria is met. You investigate what happened. The outcome of that investigation is plant failed to perform or plant performed as expected. If failed to perform, out of compliance with PRC-029, but the PRC-029 stands on itself, right?

MR. AL-HADIDI: Right.

MR. PATEL: That's the debate.

MR. AL-HADIDI: Right.

MR. PATEL: We can talk about Nath's questions. I have the concerns with that, too, but we are not debating. I think let's not link incorrectly the two standards. The only reason for PRC-030 is we cannot investigate each and every Ride-through. We put together a criteria, 10 percent, 20 megawatt, 4 second. If that's met, we'll investigate. Answer could be plant fail to perform, out of compliance with PRC-029.

MR. AL-HADIDI: Yeah, absolutely right. Right now, PRC-002 is doing the setting for PRC-024, and it's all the -- all the -- all the compliance part is done with the PRC-002, but we can discuss offline. Thank you.

MR. KAPPAGANTULA: One quick question. Can you shed some light on -- oh, Srinivas Kappagantula, Arevon Energy. Can you shed some light on why doesn't the definition specify voltage and frequency disturbance like you had on one of the slides, especially when you looked at the IEEE 2800 definition? It appears to cover over-current type issues for electrically-closed faults. Any context to that would be great.

MR. ANTHES: So why we didn't explicitly say voltage and frequency disturbances?

MR. KAPPAGANTULA: Yeah. Yeah.

MR. ANTHES: Well, I think, you know, as I read the glossary of term definition for "disturbance" that I put up on one of those slides -- I don't know if we could flip back to that. It's probably 10 slides back, so maybe it's not worth the effort, but it does talk about system, perturbations changes to ACE. ACE, in my mind, frequency disturbances, system perturbations would be any electrical disturbance.

MR. KAPPAGANTULA: So you're relying on the glossary of terms definition for a disturbance.

MR. ANTHES: I think that was our thinking --

MR. KAPPAGANTULA: Okay. All right.

MR. ANTHES: -- was to lean on the defined terms and the glossary of terms as much as possible.

MR. KAPPAGANTULA: Okay. Yeah. In that case, if -- when you're making a definition, maybe capitalize the terms so it is in our glossary of terms.

MR. ANTHES: I think we did.

MR. KAPPAGANTULA: Okay. All right.

MR. ANTHES: We should have.

MR. KAPPAGANTULA: Okay.

MR. ANTHES: I believe "disturbance" was

capitalized --

MR. KAPPAGANTULA: Okay. Great.

MR. ANTHES: -- and "bulk power system" was capitalized.

MR. KAPPAGANTULA: Thank you.

MR. ANTHES: Yeah.

MR. BENNETT: Okay. So I believe we've hit lunchtime here and we've come to a stopping point for the early afternoon. So thank you to our panelists. That was a great presentation on some very technical terms that we're trying to make it through. And just in addition, I believe we're going to utilize Slido over lunch, so when you get a chance, take a -- take a look. There's a poll out there on this definition. The software will walk you through that. It'll ask you what your favorite one is and see what you support, and maybe give us a data point to see if there's some industry support that'll help foster some decisions in the near future.

So with that, I think we are scheduled to come back here at 1:00, after lunch, and we will start up again, so thank you so much.

(Off mic comments.)

MR. BENNETT: Yeah, there'll be more to come on Slido later. There's going to be some additional ones. So we've -- to make the most of our agenda, we've had to shuffle a couple things around, but there'll be some additional polling later.

(Luncheon recess.)

MR. BENNETT: Okay. It's a few minutes after 1:00 here, and I believe we're going to start to pull our panel together and move on with our afternoon session here.

I will say that the Slido poll, it was open over lunch, and we're going to be shutting that down shortly, and we'll review the results of that initial poll here later this afternoon when we get to the other Slido portion of our conference here. And just kind of a disclaimer or a heads up, as the results of those polls, those quantitative results isn't necessarily the path forward on a certain item, but it's definitely helped framing the discussion for some decisions that are going to have to be made over the next week or two. So just please continue for that, and there's a lot of value there.

And with that I think, Jamie, I'll have you walk us through Milestone 2 of the implementation plans, and I'll turn it over to you.

MS. CALDERON: All right. So detailed, very thorough review, which will actually be a summary in about 15 minutes.

Implementation plans are incredibly important. All of the details that are within the standard are, of course, equally important to be able to say what's the measure of compliance? What do I need to do? But the implementation plan holds those details as to when, especially when we have the complication of three different standards coming together that interrelate and have phased-in implementation, compliance extensions. There's a lot to consider here when we're looking at the implementation overall.

So the slide, please.

So what is an implementation plan? So just starting from the top down, they're created for new or modified standards. They are created for retiring standards. They're created for new or modified definitions. And it's entirely to ensure that there's no overlap or gaps in time between versions, making sure that there's a very clear definition of when something will become effective and when something will need to be complied with.

Next slide, please.

So the effective date. Key terms within the sections of the IP is that you're going to have an effective date that's listed. You may have more than one. It'll be either a specific date, say, like January 1st, 2027. It may be a time period after approval by governmental authority. So there's going to be six months after the approval by the applicable governmental authority, which, in the U.S., is generally FERC, and, of course, in Canada it's going to be the provincial territories and those governmental authorities.

So it could also be something else where you have a time period after another standard becoming effective, which adds a layer of complication. Putting together a Gantt chart of this was something I initially started to do with all three standards, and guess what was unable to accomplish? And that's pretty much because we've got a phased-in implementation plan portion of this as well. So included within the effective dates are those. There's retirement -- a retirement date, which is generally immediately prior to the effective date. So something takes place and is effective on January 1st, retirement date's going to be December 31st, the year before. There's going to be general considerations, things that you need to keep in mind as you're going through implementation, something that might be impacted by another standard, something that needs to be, you know, adhered to or communicated with your regional entity or perhaps another entity within your footprint. All the things that could be, you know, brought into the conversation need to go into that section.

And then there's things that are just also just standard specific. In the case with PRC-028, there is actually a whole section for compliance extensions because there are things outside the entity's control: supply chain issues, you're not able to get contractors and testing engineers onsite, but you've made good-faith efforts and you can demonstrate that. Compliance extensions are built into PRC-028's implementation plan, and that's their -- considered as other standard specific.

Next slide, please.

So phased-in implementation plans, the bane of compliance, which is -- like, Howard was alluding to earlier, where you say 20 percent of these types of units, but then, of course, the number of units you have changes after the couple years, and when do you calculate that a hundred percent benchmark? Is it based off of when the plan was originally initiated, or is it based off of your current as-of-day asset list? It can be very, very complicated, and nuances are something that compliance deal with on a routine basis.

So we still do these even despite that because we can't have your entire fleet come into effect all at once. We can, but, you know, we try to avoid that. The idea of not having everything in all at once is the whole reason for having that phased-in implementation. So it'll generally be milestones after the effective date. So within PRC-028, we have 50 percent three years after the effective date, meaning FERC approves it. Three years later, you have to have 50 percent of that complying with PRC-028. And this is where it gets complicated because we can't give an exact date because we can't tell you exactly when it's going to be approved by FERC. Generally, we know when we're going to file it, but then it could be one quarter. It could be the first day after the first quarter. It may be delayed and end up being sometime in the second quarter.

So once we have that date, we can provide very clear guidance and a specific date, but it does become difficult to do earlier on in the process as we're seeing with the IBR registration initiative and bringing new Category 2 GOs into the mix. They want to know what and when, and so this kind of gets into the reason as to why we can't give those dates because they are subject to change based off of these trigger points within the process.

So examples of, again, of phase-in implementation, percentages facilities. There's also Requirements 1 become effective on X date, and then Requirements 2 through 7 become effective at a later date. Sometimes these are just due to the nature of how the requirements are written. One may be -- have a process, and then 2 through 7 would implement that process. And so there could be even a combination of that, which we see within the standards that we have for PRC-028, 029, and 030. It's somewhat of a gambit of it, which makes a little bit more complication, but it's why we wanted to have the discussion here today and have a quick panel discussion on as well because being able to comply with these standards is as important as being able to know what's in it and having that criteria very well understood, is being able to build out your compliance program in advance, making sure that these things that are known issues on the front end considerably with supply chain issues.

You know, that's been talked about earlier today with having access to sufficient contractors or vendors. If everyone tries to go get that done in one month just prior to the effective date or the approval -- or the -- that final compliance date, it's going to be impossible to achieve just because you're not going to be able to get that. So we want to make sure that there's preparation in this. It's all about planning.

Next slide, please.

So just overall, PRC-028, it's a new standard. What that means is that there's not a retirement that's coming with it. It's an entirely new standard. And what's in there is "shall become effective on the first day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard," which probably March or April 1st. Probably April 1st will be the first day of the first quarter after approval, assuming it gets approved in the first quarter. That's, of course, subject to change. If it doesn't get approved in the first quarter, it'll be, of course, down in July, but these types of things become a little bit more complicated.

Next slide, please.

So within PRC-028 again, we have a phased-in implementation for several things. One is for your existing IBR resources, those that are in commercial operation on or before the effective dates. There are also the new BES inverter-based resources. There's also the non-BES inverter-based resources. These are going to be the existing generators, the existing IBR that meet that new Category 2 designation. There's also going to be new ones coming online as well. So there are four sets of IBR within PRC-028 that you need to be aware of. They each meet this phased-in implementation plan of 50 percent of them by a certain date that are in -- that are in effect, but new ones have their own information.

So on the next slide we'll get into that.

So for existing IBR, your existing BES IBR, 50 percent again by three years after the effective date PRC-028, and a hundred percent of your BES IBR by January 1st, 2030, and that 2030 number is from the FERC order and is non-negotiable. We do have within PRC-028 the ability to have compliance extension, again, for the cases that are outside of your facts -- or your circumstances and/or ability to control, things like supply chain issues. Again, there's a potential to go past that 2030, but you do have to be able to demonstrate that.

New BES IBRs, so those coming into commercial operation, but might be in the current design phase after July 1st, 2025. That's to give a little bit of buffer for things that are currently iron in the ground, going to be coming online within the next year or two. We want to make sure that we're giving enough bandwidth or lead-way for at least some of those that are currently being developed. But on or before October, 2026 entity shall comply with requirements R1 through R7 by October 1st, 2026. So that's going to be the cutoff date for new BES IBR. After that, everything needs to comply.

Next slide.

Existing non-BES IBR, a hundred percent by 2030. That's just the blanket rule, everything by 2030. But the existing non-BES IBR, within 15 months following the effective date of the standard of the commercial operation date, whichever is later. We've been looking to make sure that there's a really clear consistency on when the Category 2 generator assets are going to be applicable. We have a cutoff date for that compliance -- or I'm sorry -- for that registration date for new registrants by May 2026. So what we've done here is make sure that nothing's going to be held compliant for those Category 2 generator owner assets prior to that initial cutoff date. Try to encourage early registration. Don't want to penalize people for coming on early and becoming compliant with standards early. We want to encourage early compliance, but we're not going to penalize people, you know, prior to that May 2026 date.

So again, there's the process for the compliance extensions built into PRC-028, and that's intentional and very important to ensuring that we have a strategy that can be implemented. You go after your highest-risk assets first, perhaps the larger units in your fleet first, and then you scale down as you're able.

Next slide.

For Project 2020-02, we're looking at PRC-029. This also is a new standard. We do have within this project a component that is PRC-024, and that PRC-024 piece will have a new version that will become effective and the old version will become retired, of course. But PRC-029 shall become effective 12 months after the effective date of the applicable governmental authority approving the order approving the standard.

And on the next slide, this is where the key pieces of information is. There's capability-based requirements. This is design, the ability to do studies to demonstrate your IBR will Ride-through, have the capability of riding through. This is going to be demonstrated through studies. This is going to be demonstrated potentially through EMT evaluations being able to identify and demonstrate that you can meet the Ride-through capability. For BES IBR, it's the effective date of the standard, and the non-BES IBR, again, this is the Category 2, we're talking January 2027. And that's in line with we're trying to not have everything come in all at once for Category 2 GOs, so we're staggering those out and we're working with compliance and registration to ensure that happens. So within this batch of standards, we've looked to say January 1st, 2027 is reasonable for these new -- these new -- these new generator owners coming online.

So that's the capability-based Ride-through criteria, and this is a little bit of a different phased-in implementation plan where we have a single requirement that has different aspects, one being that design base that you demonstrate through studies, and then it becomes the performance-based criteria that that becomes effective later. So we're looking at --

Oh, sorry. One slide previous. Yep. One slide before. No, before. Yeah. Thank you.

So performance-based Ride-through criteria is for both BES IBR and non-BS IBR. Nothing new here. Align it with your PRC-028 implementation plan, and that's because within PRC-028, you're installing new equipment, you're working with your vendors, you're working with supply chain, and you're getting that installed. You shouldn't be required to demonstrate performance at a generator that you haven't installed that equipment at yet. The implementation plan for 0-028's already sufficient to demonstrate that you've got the -- you've got the risk resolved by having the monitoring equipment installed and you have the capability of demonstrating what you're doing onsite, how it's performing. And at that point you become -- your performance-based Ride-through criteria needs to be demonstrated.

And now we can go to the next slide.

All right. So for Project 2023-02, new standard again, PRC-030. What we're looking for is -- this is the analytics that base -- work off the same as 029. We have an IP revised and current draft for formal comments, so I actually cannot take questions on PRC-030, but this is a public forum and we can briefly talk about this because it's currently under ballot.

But what is in the revised IP? We recently did pass ballot, but due to some necessary conforming changes to make sure that the PRC-030's implementation plan was in line as intended with PRC-029 and PRC-030, it's currently out for ballot just for those conforming changes and some small revisions within the requirements for R2. So the IP is currently out for ballot. We did remove the performance-based, capability-based language from that IP, so now it's only focused on just on the next slide when it becomes effective.

So it's later of the first day of the first calendar quarter that is 12 months after the effective dates or approving the standard or the first day of the first calendar quarter that is 12 months after the effective date of the applicable governmental authority order approving Reliability Standard PRC-029. All that to say this is meant to align with your PRC-029 rollout, and PRC-029's rollout is meant to align with PRC-028. So these are all tied together for that -- for that same basis of performance data criteria and having the analysis that's triggering that data, and having the data installed and that equipment being installed at those sites are all in conjunction and working together. So it's that three-legged stool we talked about yesterday. It's one solution.

While there are three different IPs, they daisy chain together intentionally to make sure that we're not putting anyone into a compliance bind by having a gap. If you don't have disturbance monitoring equipment installed, you shouldn't be held accountable for performance that you can't demonstrate. So that's built into the IPs.

And at this point, I think we can go to the next slide, which should be -- okay.

I did add this in just to -- as a callback from yesterday. We talked about how these tied together, voltage frequency excursion occurs, and so you see these two standards on the right. PRC-029 and 030 tie together, and then on the disturbance monitoring side, PRC-028 on the far left, all to say that all three of these go together, and this is just a visual representation, again, as a callback. If this didn't make sense yesterday, maybe it makes less sense today, but hopefully it makes a little bit more sense. It makes more sense to me than it did when I originally made it, so this is good.

But when it gets to making sure that you have an understanding of this, ask questions. Reach out to your regional entity. That compliance staff is there to help provide that guidance, so as these come out, don't guess, of course. I don't think any compliance officer is doing that, but if you have questions or concerns, please raise those, bring those up. The regional entities are there to help. And with that, I think we can go to the next slide and take questions.

MR. BENNETT: So, Jamie, on this one, I was just going to ask, would you prefer to have questions on this now or kind of morph into your panel discussion?

MS. CALDERON: Let's just do the panel, yeah.

MR. BENNETT: And do it all at once.

MS. CALDERON: Yeah. Yeah, let's do the panel.

MR. BENNETT: Okay. Let's just -- let's just do that. Okay. So it looks like the panelists are starting to make their way to the stage. So this is going to be kind of continuing the conversation on implementation plans and effective dates. And Charles Yeung, our moderator from earlier, is back with us as well as Jamie to help moderate this conversation, and with that, Jamie, whenever you guys get settled up there, please start in.

MR. YEUNG: So Jamie kind of recapped where we were, and I think it'd be good to put that other slide back on, her last slide with the three standards. Is that possible? I think that's a good reference for what we're going to talk about on this panel. I need to bring up the questions. Excuse me.

(Brief pause.)

MR. YEUNG: So let's start with introductions. Maybe we'll start on the end, just who you are, who you represent, please.

MR. HAKE: Yeah. Hey, everybody. So Sam Hake here. I'm a NERC compliance engineer with a AES Clean Energy. We're a renewable energy developer.

MS. JONES: Good afternoon, everyone. My name is Rhonda Jones, and I lead the NERC compliance efforts for Invenergy, and we're a developer and operator of many projects throughout the United States, and we're headquartered in Chicago.

MR. GUGEL: And I'm Howard Google, vice president of regulatory oversight at NERC.

MR. PATEL: Manish Patel, Electric Power Research Institute.

MR. YEUNG: Again, I'm Charles Yeung. I work for Southwest Power Pool, a member of the Standards Committee, and we know Jamie is.

MS. CALDERON: Yeah. My name's Jamie Calderon with NERC Standards Development. My computer seems to have just bricked.

MR. YEUNG: Crowdstrike?

MS. CALDERON: Yes, probably.

MR. YEUNG: Well, I think implementation's a real important issue. I believe two of these standards have already passed. One is under a final ballot, I think the PRC-030, and hopefully as far as this conference is concerned, we'll get to passing a standard for PRC-029.

I think one of the things probably not recognized because it's still in development is the issue of exemptions. That's going to be -- yet have to be finalized exactly what that would look like, but I think that might have some bearing on this implementation. So maybe the panelists can consider some of the comments we've heard so far about exemptions and implementation because with exemptions, certainly there's different types, different impacts, and perhaps impacts on the implementation, too.

So the first question is, given the complexities of these three standards -- PRC-028-1, PRC-029-1, and PRC-031 -- what strategies would you recommend in synchronizing implementation to avoid conflicts or gaps in compliance? Again, with the explanation Jamie gave, they're all one big happy family, so we need to synchronize those together. And then what considerations are needed to prevent potential overlaps or inconsistencies in that implementation? So you want to just start on the end?

MR. HAKE: Yeah. Yeah, absolutely. So a couple of points to make here. I think, first of all, we should expect overlap. I think that currently in the existing implementation plans, that is acknowledged, as Jamie just presented. I do think that we have some concern over the differentiation between the design portion versus their performance. Particularly for PRC-029, a lot of the challenges that we've heard discussed -- you know, OEMs being out of business, modeling information not being available -- those are really going to impact us on the design side first, right? That's the first thing that we have to do. And so I think that for our -- my personal view, I think that the link that we currently see through the performance requirements needs to be replicated also for the design. I'm not sure that we can really cleanly differentiate between those.

And then the second main point I wanted to make was also referring to some discussion that we heard yesterday about the design cycles for the equipment capabilities here. So it was on the order of five years for the design cycle. That's five years to have the equipment available, not installed in the field, looking at another three years for deployment. So with eight years there, we're already at the very end of the -- you know, the 2030 hard date. So we're certainly confused and concerned about that, and I think that that's something that really needs to be seriously considered as the Drafting Team and NERC moves forward.

MS. JONES: Some of the things that we've done at Invenergy to kind of prepare, yes, definitely we share some of the same concerns about design with some of our equipment. But one of the things that we've done to kind of help get ahead of this is that we've already started to kind of develop, like, timelines, in specific, to the type of equipments that we have. And so we kind of map out current day, if this goes into effect, what would it look like. What would I need to do today to be ready from a design perspective, being probably proactive, and looking at equipment and who we're going to procure that from, and what does that look like? So we are really, like, starting earlier to kind of just planning side of it to really help us to make sure that things are coordinated, and kind of almost doing a gap analysis early to just kind of see where some of those needs will be and trying to fill those in and be proactive in that regard.

Also, too, as Jamie kind of talked about early, kind of prioritizing those high-risk assets and those that we would probably need to give -- that will require the greatest need of support. Say if an OEM is no longer in business, what is our strategy or contingency to kind of come up with how do we articulate design in those cases and respond accordingly? And one of the things that we feel is just really big here is just we can't underestimate the power of kind of mapping it out almost project style. I have over 75 plants that I have to get ready for this, and by the time, you know, we have to start implementing and kind of installing equipment, I'll probably be at 85, 90 plants that I have to do this for. So just really strategizing early on a timeline and a schedule to get the different phases done.

MR. GUGEL: Yeah. I'll kind of tie this back into the previous panel's discussion. I think it's going to depend on how the next version of PRC-029 deals with exemptions. I think the closer the exemptions and the performance expectations map to what everyone is saying that their current units can perform to, it'll be easier to demonstrate that than if it varies from it. So, you know, if there's a, an expectation by most folks that, yeah, we can meet PRC-024, maybe if that exemption is closer to that curve for existing units, it might be a little bit easier to kind of work through and demonstrate that than if all your existing units you needed to demonstrate something that's a little bit different from that, and would be different documentation that you have in place.

MR. PATEL: I don't have too much to add, but before I forget, I think we need a Ride-through standard for Jamie's laptop.

(Laughter.)

MR. PATEL: Anyhow, so I think what Howard said is absolutely right. I think it depends on how PRC-029 looks like in the next couple of weeks. But beyond that, I think credit to all three standard Drafting

Teams. I think, my personal opinion, the implementation plans were pretty synchronized. I think we can always debate is the time allowed enough or not, but I think there was great deal of effort in coordinating implementation plans of the three standards, and there is an opportunity to tweak those based on what the changes might look like.

MR. YEUNG: Yeah.

MS. CALDERON: I have a follow-up question if I may. Yeah. When it comes to the challenges with specific equipment, is there a particular type of equipment that would be perhaps more difficult to secure? And I don't know if you have this off the top of your head, but just when it comes to the installation of new monitoring equipment, is there any that are more challenging to do on the front end because, like, transformers have a long lead time. I'm just unfamiliar with the disturbance modern equipment that's being required at the plant level and the -- and the sub-plant level as well.

MR. PATEL: Right, right. So I think the PRC-028 Standard Drafting Team debated that a lot, right? It's one thing to draw up a CT or PT distance monitoring equipment on a piece of paper, a single-line diagram. It's another thing to actually go out, get an outage, procure equipment, get the panel on which you will hook on the equipment.

So I think the 028 team did take into consideration all that, with the expectations or the directives from Order 901, right? Order 901 is very clear in terms of when those standards need to be fully enforced. But then if you remember, and some of you may have noticed that we realized that, you know, it may be challenging. I don't know how many plants we are talking about. I think when we were only writing a standard for BES IBRs, we had some idea about how many plants we were talking about. I think someone at NERC staff had pulled up some data and said about 800 to thousand BES IBR plants. But then we rolled in non BES-IBRs, and we have no clue how many of them are out there. So long story short, we have to honor the directive of the Order 901, and we have to realize that there are some practical limitations based on which, you know, equipment gets installed in the -- in the station or at the plant.

So the framework, there is a framework in the implementation plan. If the NTT provides reasoning that beyond -- that is beyond their control, right, then there is a framework in the implementation plan of the PRC-028 standard that allows to seek exemption or seek extension -- sorry -- extension of implementation plan from the compliance enforcement authority. So anyhow, I think the PRC-028 team did as much as they could to honor the directive and realizing actual, you know, problems that might come up as industry goes installing equipment.

MR. YEUNG: Thank you, Manish. Second question, and, Panelists, if you have things to add, maybe you can elaborate with the second question because it's very related to the first one. So question is, what do you anticipate would the -- with the -- will be the most significant challenges when retrofitting or modifying the legacy IBR -- and that's kind of what Howard mentioned on the exemptions -- to comply with these new standards? And the question's kind of silent on which one of the three, it just refers to all three, but if there is a particular one that you want to call out, I suspect there is, that's more challenging than others, that'd be helpful. So can you share any practical solutions or best practices that have proven effective? And I think we heard some things about getting started early, so thoughts on that, Panel? Go this way or start down there again?

MR. GUGEL: Yeah. No, I can start again. So I think that one of the huge challenges that we are concerned with, again, as been discussed previously, is resource availability both on the GO side, the OEM side, really across the board. Having a confusion and uncertainty on the path forward makes that extremely difficult, and I think it's going to hit every part of the industry. And then I think the second point I wanted to make here as far as challenging for retrofits, you know, I'm focusing on PRC-029 here, although I'm not sure I would want to opine on which is more difficult. But so specifically regarding the exemptions, I made a similar point yesterday about hardware- versus software-based exemptions, and again, this goes into planning. We're not sure how to interpret this and what to do about it.

I do -- I just want to caution that I'm concerned that the focus on hardware- versus software-based limitations is missing part of the point. A lot of our concern, again, is on the modeling side, and as I understand it, models are very literally a software-based representation of the entire system, which includes hardware and it includes software. So again, just driving the point home that having exemptions only for hardware seems to be unnecessarily restrictive and makes the assumption that the software issues can be resolved much more simply, which I'm not entirely sure is true.

MS. JONES: Just to kind of add to that, I think for us kind of doing just that commercial/economic assessment now and being a part of, like, kind of our long-term forecasting is, these solutions, even if we, you know, do exercise exceptions, is going to require a financial -- increased financial investment, and that's just the reality of it. And I think what's hard is they're saying, hey, Rhonda, how much is it going to cost, and I'm saying, I don't know yet, but you want me to buy it tomorrow. And just trying to figure out what does that number look like, but also, too, you know, the challenge is kind of having that conversation with the OEMs to kind of help us to get to a number that's a strong, strong estimate of that.

So understanding the commercial and financial impact, but also, too, being able to articulate the return on this possible investment that we're making. Hey, Rhonda, we're going to do this, and what does that mean for us as far as production? Hey, Rhonda, what does this mean for us as far as return, and kind of substantiating that is something, too, that's -- can be a little bit of a challenge in that regard because it needs data. Just like my neighbor here, I think modeling -- I'm happy that we do have an in-house modeling team to kind of help us with that. But that also, too, is going to really kind of increase the resource need there as we try to articulate our position in that regard.

Also, too, we worry about -- another big challenge is termination of services for the few OEMs that we have equipment for that are no longer in operation and just trying to figure out what is that -- you know, what is that story that we tell from an engineering perspective to give our best understanding of what to expect of these devices. And then also, too, just the collateral impact to other standards. This is just not PRC, but there's a lot of other NERC standards that are going to have to be addressed once the standards are approved and kind of putting things in place to kind of address the -- I call it the collateral impact of these standards going forward. I think about my facility ratings, et cetera, and safety and also, too, and the analysis and impact there, which is of great concern.

But hey, yeah, those are the concerns, but how do you kind of address those? I kind of encourage folks that have never really talked to their OEMs, get to know them today. Establish a relationship with them. Really get to know about your fleet and about your equipment, about the type it is. Find those, those tech sheets, those specs. Sometimes if you all are in the business as we are of acquiring already existing projects, make that a part of your turnover package. To really, really learn these assets, you're probably going to be more of an expert on the asset, and that expectation is to know it there. You can start having these conversations now even before the standards get approved to just knowing what you're working with. So those are some things to do to kind of offset it.

And then we are a big fan of the, you know, hardware exemptions, and I think that that's a good thing, but also, too, you can start now building that story and what does that look like in order to substantiate it. I don't think it's solely on the OEMs to do it alone, but, you know, when you're an operator, you're close to the action. You can tell the story about effectiveness and what your limits are.

Part of the strategy that I have in my shop is always about optimization. What is the optimization story? And that's something that's -- with or without PRC-029, we're always in a position to demonstrate is my equipment performing to the best of its ability and this is why. And I think an optimization story, even if it is used to substantiate an exemption, is something that is knowledge that can go a long way in helping you.

MR. YEUNG: So let me kind of follow up with you and Andy, Rhonda. As far as the implementation time frames, yes, there -- we have a lot of these. Is there any particular one of these standards where the implementation time frame really is just, you know, as proposed is more problematic, or are your concerns through both 028, 029 and 030 implementation?

MS. JONES: I would -- I would say that -- you know, also, too, if I could have a longer runway, I'll take it because like I said, I have about, you know, 70 to 80-plus projects to get ready for, and I just think I'm concerned because one of the biggest thing is just the bottleneck. And right now it's hard to predict if I went forth to my OEMs with what my needs and supports are, do they have the capacity to fit the timelines that are being proposed and those that we have internally at in Invenergy. And so that's one of the things, just trying to merge their availability and capacity with ours. And sometimes I do kind of predict that it may really be challenging to meet that, and so that's one of our biggest concerns.

On the disturbance monitoring equipment side, we haven't gotten a lot of concerning feedback about the availability of that, but maybe a lot of people haven't started asking about it yet, so we don't really see a lot of big concerns there. But once everything starts to kind of get going and going out of the gates, we are concerned that just from just bottleneck of services is going to be a challenge.

MR. YEUNG: Supply chain issues. Andy, anything to add to that?

MR. HAKE: Yeah. So I think I agree with pretty much everything that was just said. We're a big fan of the phased-in implementation for PRC-028. I think that's very, very important. I made the point earlier during the first question that I personally believe that the design portion shouldn't be separated from the performance portion. I don't see that needing to be -- to be separate and should also be contingent on the PRC-028 information.

And then the last part I'll mention here is on the newly-revised PRC-038 implementation plan. Again, personally, I think that the link there to PRC-029 is important. I'm not sure how much we can discuss that today, but just putting that out there that, again, I view all three standards as being somewhat sequential, and I'm not entirely understanding why that revision needs to be made after it was already approved.

MR. GUGEL: Yeah, Rhonda, if I could pull on a thread of something you mentioned earlier because it's not anything that I had considered. What are the things in PRC-028, 029, and 030 that would cause changes to your FAC-008 policy?

MS. JONES: Well, like, when we talk about some of the auxiliary equipment that, these changes that we're making, if PRC-029, the curves are approved as proposed, we think about some of the safety concerns with the equipment down the line. So that's where kind of that comes in when we're looking at the transformers and stuff like that. In certain events, in the scenarios that they showed, it's like, well, wow, I'm not only worried about the actual inverter itself, but worried about some of the other auxiliary equipment in that regard when you look at it from a scenario perspective.

MR. GUGEL: Okay. Yeah, I just -- I mean, the time frames that you're talking about, let's assume that, you know, that the curves in PRC-029 stay the way that they are. You know, the thermal constraints for most of the auxiliary equipment you'd be talking about, especially when you're talking about transformers, CTs, PTs, breakers and switches, seconds is not going to be enough for that to heat up and cause any kind of -- I don't think, at least in my experience, wouldn't be enough to change a rating for any of those. Now, if it was extended, protracted, maybe, out for 15 to 20 minutes, which is not something we'd really be talking about here, then I could see how that could be affected. But I'm struggling a little bit trying to figure out where it would change a -- that short-term thing would change some sort of a rating for your facility that isn't already taken into account in your existing FAC-008 process. Yeah, that's something I'm

MS. JONES: (Off mic) probably spent years on, but definitely, that's something that came up about the safety of the equipment and its ability to react, and how it just can have that domino effect down the line.

MR. YEUNG: Okay. Manish, your comments, and if you can throw in a joke, it'd be appreciated.

MR. PATEL: I'm running out of them. So I'm going to take a slightly different way to answer this. And so, you know, PRC-023 transmission, really loadability standard. PRC-025, generator relay loadability, standard. PRC 26, stable power swing standard. All those standards, when they were written, either concurrently or immediately after, there was a document produced either by the Standard Drafting Team or some other technical committee or working group at NERC that shows how to do calculations so that, you know, people know how to meet the requirements of the standard, right?

PRC-024, there is actually a document that -- out there that shows three methods to do calculation for converting voltage from high side of the main power transformer, the generator step of transformer, to synchronous machine terminals. And three years ago or so, some solar developers came to say, well, you have a document that shows calculations for synchronous machines, not for, you know, solar plants. So System Protection Working Group -- I work with them -- we put together a white paper that shows one method that, as I mentioned earlier this morning, that hopefully will get approved by RSTC.

What I'm trying to say with all that back story is PRC-029, it's a Ride-through standard. There is no framework out there to show a sample method to evaluate your plan with and show that either it meets or does not meet the Ride-through requirements, right? So I think as we think about implementation plan, we need to think about the Joe Smith out there working on putting together documentation to show compliance. Does he have or she has tools and calculation methodologies to go along, right? As written the implementation plan, assuming that the standard gets filed, approved by FERC early next year, then within one year, so first quarter or second quarter of 2026, we are looking at fully enforced standard, right? Do we -- do we have -- have we provided tools, methodologies to the industry that can be followed and then that can be applied to this thousand BES and then, in another nine months or so, non-BES IBRs needs to be fully enforced. Can all these calculations be done in some of this?

You still need to go back to your OEMs, right, get some information that might be necessary to show compliance or seek exemptions and all that stuff. So I think -- I think we need to about some of those things when we talk about implementation plan. I don't have any comment on PRC-028 implementation plan. I'm a chair of the Standard Drafting Team, and as I said, we have done best possible. And I think PRC-030 is slightly different in nature, but I think when we think about PRC-029 implementation plan, we need to be very careful that we provide industry time and tools, right? There is not a single literature document out there that shows this is how you will evaluate Ride-through capability. Ride-through, this is first-of-a-kind regulatory standard, right? There is no tools in methodology out there, I think.

MR. YEUNG: So we should've made you chair of PRC-029, Manish. There wouldn't be a question. Jamie, anything to add?

MS. CALDERON: No, not on that question.

MR. YEUNG: Okay. So the next question is about new generators. As mentioned, we also now have a Sub-

Category 2 type of registration that's going to be under compliance for these standards as well. So since NERC is expanding their registration criteria for the GOs, how should companies approach the integration of new assets or changes in ownership to ensure seamless compliance, and what are there -- what are the key considerations to keep in mind? I think we already heard some of the things about, you know, tools, right, especially these new players, as you said, the plain Joes who have never been subjected to noncompliance.

MS. CALDERON: Well, if I may expand on that, the impetus for this question as well is we see a transfer in ownership much more with a lot of the smaller IBR than we're seeing with, like, conventional generation where whole companies come and go. It seems very quickly we have foreign-owned investors, and there's a lot of interchange between some of this ownership with IBR that we don't see traditionally. So there's an additional layer of complication to this question then, I think, is why we wanted to bring it up to the panel.

MR. HAKE: Yeah, so I'll start again. This is -- this is a fun challenge for sure. So I guess what I'll do is just explain a little bit about how AES has kind of attacked this, at least very, very early stages, to be clear.

So we've come up with our list of potential new Category 2 sites, right, based on all the data that we have on our operating fleet, begun the effort of gathering data in the field. We believe that it's going to be a tremendous resource drain and constraint on us in order to get this information. It's not trivial. So even though, currently, we don't have a super firm understanding of what exactly are we going to have to do for these Category 2 sites, we figure we can at least get some stuff started. You know, we're going to need that data no matter which standards apply.

And then to more directly address the question about change of ownership for projects or how are we now treating these Category 2 projects, especially new ones that are coming up, and it might sound like a bit of a simple answer, but, essentially, what we're doing is treating them the same way that we do our Category 1 projects. So again, because we don't necessarily know specifically which standards will apply, we are taking a conservative approach and assuming it's going to be most of them, if not all of them.

It does raise a lot of concerns and challenges in working with our contractors trying to figure out what is going to happen. You know, they don't like uncertainty just the same way that we don't, but that's essentially what AES Clean Energy, our approach has been thus far. And we're certainly eager and awaiting additional information so that we can, you know, continue to plan and make sure, again, touching on the resource availability point, that we have all the people in the right places in order to actually make this happen.

MS. JONES: I echo -- I echo that process very similar to how we do it in our shop. With any asset, we have about definitely 10 or 12 that'll come into -- under Category 2, and we just kind of stress test them under the most extreme scenario. Now, our hope is that the curves will come in a little bit, but nonetheless, we just try to, in our shop with our NERC readiness process, is try to understand now, well, what do we need to do to get these facilities ready to be able to demonstrate compliance, and it's just starting early and trying to figure it out.

And we do have one or two cases where the vendor is no longer there and just trying to, on our own, be able to substantiate their effectiveness to the grid, which we think is most important, and being able to show how they continue to support grid reliability in the absence maybe of some of that information because the OEM is no longer around.

MR. GUGEL: I like what I'm hearing, I mean, and I think that's an excellent approach for folks to be taking. The other thing is that as assets change hands, hopefully there's a communication that occurs to let folks know, hey, by the way, are you registered with NERC if you're -- if you're selling an existing asset or changing it, and if not, you might want to reach out because the world's about to change. But yeah, raising that awareness, too, it would help -- it would help us and help them, I think, entirely to make sure that we've got awareness raised on those areas. You know, the fortunate thing is we don't register assets, we register entities, so once you're in, you're in and, and you're in the know, if you will, so yeah, but the approach that y'all are taking I think is really good.

And then just a reminder that since these are, you know, non-BES assets, standards would only be applicable as they're changed or as, you know, definitions kind of change in that area. So it's going to be a process of standards development as each one of -- each standard is modified to see whether or not these non-BES assets are included or not.

MR. PATEL: So I don't have much to add to what Howard said. When I read this question, the raw thought that came to mind is, you know, when you sell your home, you have to -- you have to sign this disclaimer about the status of the home, what's in it. If something's broken, you have to declare it and all that stuff. I think -- I think there might be a checklist out there that someone can put together that one owner gives to another owner, then the ownership changes, and, you know, let the new owner become aware of what they're getting into. I don't have much to add here. I think it's an administrative process, but all those entities who play in this non-BES assets world need to catch up to the reality that NERC standards would apply to those assets now.

MR. YEUNG: -- communication for the new owners, and, of course, NERC has already a plan for registering these new owners, too.

The next question is a little bit maybe kind of -- kind of going back to some of the things that already been said, so I'm going to revise it a little bit. The question is, how does supply chain issues impact the timely implementation of these new standards, particularly in terms of retrofitting existing or new installs, and what proactive measures can be taken to mitigate these potential risks?

And I think we are over these past couple of days, we've heard a lot about the PRC-029 impacts of these -- implementation and how the supply chain might impact that. So maybe kind of talk more about maybe the other two standards, 028 and 030, and, Manish, I think you already opined on that a little bit, particularly, again, this is about a lot of new Category 2 assets that probably don't have any type of this equipment presently.

MR. PATEL: That is true for PRC-028. It is very likely that non-BES IBRs do not have all necessary equipment. They may have some that can do some recording as required by the standard, but not all recordings that the standard requires. This will require them to -- actually, if they don't have their own engineering staff, first of all, go and find an engineering consultant who can help them, right, design the DME equipment, and then go and find folks who can actually go into the substation and install it, right? So it's going to be quite a bit of work.

In some cases they will have to talk to IBR unit OEMs because the standard requires SCR data from the inverters or the wind turbine generators. So they will have to go and talk to the OEMs about the capabilities of that particular, you know, vintage of equipment that they have in their asset. So there is quite a bit of work required, and I think that's why, as I said earlier, the Standard Drafting Team, you know, respecting the directive of the Order 901 in terms of when the standard needs to be fully enforced, still went ahead and offered a framework to seek extension, right, because again, I can draw up DME equipment right here on my notepad in matter of five minutes. It's another thing to actually go and get it installed in the substation.

MR. YEUNG: Howard, any thoughts?

MR. GUGEL: Yeah. I don't really have anything to add. I'm not sure that, from our perspective, we really understand the supply chain issue there. I do think that, as it's mentioned before, you know, volume is going to play in -- come into play here, and the fact that you've got, you know, a significant number of folks that are having to procure new equipment may bring that into play and may cause a supply chain issue.

I could be totally wet on this and some folks may be able to straighten me out on this later, but I think one advantage that these units have over maybe the traditional synchronous units are that they're already sampling a lot of information. They're already bringing a lot of data in to do all the monitoring that's necessary internally. So it may be, you know, the fact that they don't have to install some additional inputs might be an advantage, but you're still going to have to have that external logging equipment there that would be able to pull that information in. So while one part of it may be a little bit easier, there's still a lot of stuff that has to occur and would be impacted by supply chain.

MS. JONES: Nothing new to add with supply chain. I think we've kind of talked about it with just the volume and not knowing that, and just hope that we're at the front of the line is what I strive for when we start to request this equipment. But nonetheless, you know, I think the other thing that we kind of think about with supply chain is not just equipment. But one of the things that kind of came up in our analysis is the ability for this equipment to record all this data and what does that mean for additional kind of capacity, and should we be looking at that as far as something else to kind of consider as far as managing and storing that data is something also, too, came up in some of our conversations.

MR. HAKE: Yeah, I don't have too much more to add on this one. I think that -- you know, I'll mention again that in some cases, OEMs are out of business, so, effectively, the supply chain does not exist. We're early enough in the process that we haven't encountered any specific supply chain issues with particular equipment. But, you know, we, of course, share similar concerns that there's a whole lot of companies out there that are going to be requesting the same thing, at the same time, on the same timeline. And that's very concerning, right, again, from equipment and, again, from a resource availability standpoint

I think one thing that I learned yesterday that I perhaps didn't appreciate previously is that this equipment is wildly complicated, hearing from the OEMs about how, you know, even just a single turbine is a system of systems with auxiliary equipment. It's a lot of stuff that, again, everybody is going to be requesting to upgrade and have updated at the same time on a short timeline.

MR. GUGEL: I could add just one thing because it just came to mind, too. I'm going to take an opportunity here to put in a little bit of a plug. I think if you're not already a member of some sort of a trade organization, it would really be helpful in that -- in that aspect. So there's power in community, and so it would be good to join up with some other trade organization, get some of the collective thoughts that are there, and work together towards some of those solutions because sometimes working by yourself, you might come up with something, but as a community, if you come up with a solution, there's kind of the power that could occur there. And yeah, Mark's reminded me, you know, we've also got the Generator Forum that would be an excellent source for you also there. But, you know, between the forums and the trade organizations, I think there's a wealth of information that can be tapped there as you get involved in those things. So just -- it was kind of my opportunity to kind of say look for those also.

MS. CALDERON: So we've talked a bit about installation of equipment, supply chain issues, testing, and all of that. PRC-030 also has that piece about root cause analysis and being able to diagnose the fault recorder data to be able to diagnose root cause. And that's an entirely different form of analysis that needs to be proactively addressed as well. I would suggest making sure that you've got either onsite engineer or contractors, like, set up or consultants set up to be able to do that type of analysis because there will be a time limit once it's being triggered and that request for the analysis is being triggered, and it's a very specialized skillset. So that's something else to keep in mind.

MS. JONES: And that's a good point that you bring up, Jamie, because part of our -- in our planning efforts is kind of being able to design and how do we maximize the filtering of that data to help us quickly support a root cause analysis. And to be just transparent, you know, we've kind of recommended we need to build a program just around root cause evaluation. It's its own program in and of itself. It's not just this casual task of someone just flips through the paper and says what's happened, but you actually have to tell the story and substantiate it, and then talk through remediation and mitigation if that's the case.

And so in our shop, we've talked about the need to maybe carve out, for PRC-030, its own program. We work a lot with our data analytics team, we work a lot with our engineering team and our compliance professionals to kind of bring that together, but we look at the volume and the number of faults that's happened. Also, too, you have to think about your workforce and the FTEs that are going to be needed to kind of support that, also.

MR. HAKE: Yeah, that's a really good point there, and I would like to add, also, that the way that we're currently interpreting PRC-029, in some of the measures, it talks about retention of actual performance data to demonstrate compliance with these performance requirements. So, in effect, we are going to have to do a similar type of effort every single time an inverter trips offline. I know there was discussion earlier about the Ride-through definition, and we're optimistic that that can be clarified to try and mitigate some of those concerns. But I think similar to your point on PRC-030, there's also going to be a substantial amount of expertise and resources and effort involved with that, right? Every time something trips, we have to evaluate it versus the Ride-through requirements.

MR. GUGEL: Yeah. The only thing I would add is I think if you've already got a team looking at PRC-024 and any mis-operations, they're already kind of involved in that RCA thought. And if you can draw on them to maybe provide some information or some help to look into your inverter trips, that would be really good, too.

MR. HAKE: Yeah, I think that's a really good point, Howard. The one distinction I would draw is, currently, we're looking at a significantly larger volume than we would for PRC-024, so PRC-024 mis-operations. Again, not speaking just for AES, just personally, they don't happen very often, so it's much easier to deal with.

MR. GUGEL: Yeah. You just need to clone them, right?

(Laughter.)

MR. HAKE: Exactly. Problem solved.

MR. YEUNG: We have one more question for this panel. I'm just going to dig a little bit deeper into some of the things we've mentioned earlier about testing and verification to whether or not you meet these requirements, particularly 029 requirements. So what are some of the most challenging aspects of testing and verification in the context of these new standards -- 028, 029, or 030 -- probably you're going to be talking about 029 -- and especially in the case that you're going to have this mix, right, of existing, new retrofitted, it's going to be a changing landscape in your fleet. So what's going to be some of those challenges to testing and verification, and how do you ensure that testing protocols are robust now to meet these requirements and avoid, as little as possible, delays?

MR. HAKE: So I'm not sure I have the answer for that one. The first thing that comes to mind, though, are the -- some of the challenges we've talked about in modeling, right? So when we -- when we talk about verifying performance on the design side, the model has to come first. And, you know, as discussed at length here the last couple of days, getting all of that information is a major challenge, particularly for legacy products. But even moving forward, again, going back to the design cycle comment, in the short to medium, even long term, we're going to have a similar challenge. And if we don't have the model in order to run the tests, we can't demonstrate performance requirements or compliance with them.

MS. JONES: Just add to that, you know, definitely trying to nail down the modeling is going to be a -- you know, a work in process. But one of the things that came up in our shop was, is there just like this consensus testing standard that exists on how testing should be performed? And if that kind of a standard was to be developed, who is best to develop it that we can have a shared approach at how we do testing, if not just defining testing.

If I was a regulator and everybody had to define their own testing, it could really get kind of squirrely there. But we don't have the answer to it, but that's one of the questions that we're -- that we've been talking about internally, what is that consistent standard of testing that we can adopt and apply across the board and across equipment type? And that's something that we are still looking to kind of learn more of, and we think that would help to simplify things versus developing our own, this other entity develops their own, and it's just everybody has their own way of testing it, and do we -- are we achieving the same objectives? But that's one of our recommendations is to get that kind of consistent standard of testing.

MR. GUGEL: Yeah, I would agree. I think that's a -- that's an area to concentrate on. The synchronous machines all struggled through that when we first went through the MOD standards to try to figure out how to do their real and reactive power output verifications and their model verifications. And I think that these -- that the inverter-based resources have such an additional complexity to their operation, that it is going to take some specialized folks to set up those testing procedures. I agree.

MR. PATEL: So this is also kind of only a question for really PRC-029 disturbance monitoring equipment. We have been installing for a long time. We know how to commission tests. PRC-030 is kind of unique, very specific criteria in R1. I think we can come up with process, you know, to honor that.

So then PRC-029, we are not going to apply a 230 kV fault for 160 millisecond to test plant is able to Ride-through or not, right? So this begins from lab testing, solar inverter, or container testing wind turbine generator. I don't even know what to think about HVDC terminals. They're a thousand megawatt in capacity. But there has to be some sort of guidance out there that says these are some of the tests that you need to run on your IBR units, right -- the solar inverters, the wind turbine generators, the HVDC converters. Somehow convert those tests into models and then use the models at the plant level, and then a simulation engineer like me can apply 230 kV fault all day every day of whatever time duration, right?

But this is what I meant earlier that -- we wrote the standard. It will get done in one form or another here in next couple of months, and then how to show compliance with the standard, it's a big task. It begins with lab testing of equipment and then, you know, some sort of model-based verifications. And there is a -- there is a need to develop framework for all this work. Some of that, I know we're all tired of listening "IEEE," but some of that work is being carried out in IEEE 2800.2 Working Group. It takes time to develop some of those things.

We have been talking with some OEMs, you know. Testing for MVA battery energy storage inverter is very different than testing a 12-megawatt wind turbine generator in a container which is actually connected to the system, right? There are many different ways of testing. Now, I'm talking about things that I don't understand well, but, you know, a lot of things go on what can be tested, what cannot be tested, and then somehow bring it all into a simulation world and show that the plant was designed. If I was a GO, I want to have a confidence before we go commercial operation that the plant will Ride-through, right? All system disturbances, right? So I think there is a lot of work remains in putting together a framework for test and verification of Ride-through standard.

MR. YEUNG: Okay. Well, thank you. Go ahead.

MR. GUGEL: If only there was a research institute for the electric power area, there might be a way for this to happen.

(Laughter.)

MR. GUGEL: That was my attempt at humor, by the way.

MR. YEUNG: -- some questions. We're going to start in the room for this panel. Any questions? Scott?

MR. KARPIEL: Scott Karpiel of SMA America. Just curious to understand, considering some of the hurdles and issues, concerns with supply chain costs, transfer of ownership -- let's see -- the costing of upgrades, testing, modeling, you know, it all kind of stacks up. At some point, there's diminishing returns on that investment. Curious to understand if there's a possibility that a plant or an asset would be decommissioned, and, if so, how would that affect transmission in planning?

MR. GUGEL: I'm not sure I understand the question. Can you elaborate just a little bit more on that?

MR. KARPIEL: Sure. So if I'm an owner, which I'm not, right, there's a financial commitment. There's a return on the investment that I'm going to have to make to bring this asset up to current code and standard. If I were to deem that it wasn't worth my investment to do that and I decided to shut the plant down, decommission the plant, curious to understand how that would affect the network from a planning standpoint, from an operational standpoint. You know, I think there's a real possibility, especially for some of the smaller asset owners, that they may decide to just throw their hands up and close down the plant or decommission the plant.

MR. GUGEL: Yeah, that goes back to something we had mentioned earlier that definitely do not want that perverse incentive there. You know, the last thing we need is a retirement of additional capacity that's out there, but we do need the capacity that's there to act reliably. So, you know, the reliability coordinators will be the ones that will be looking at this, in my opinion, and if there's a decision made to retire, they would be able to look at that and see what the overall reaction to the system would be on that. But again, you know, that's going to be a decision that's based on the owner of that asset and then, you know, the reliability coordinator, looking at all the reliability for the area. Just my thoughts on that.

MS. CALDERON: I would -- I would add that there's substantial precedent for this type of business decision just when retrofitting units, like carbon capture, that was putting baghouses on coal units. There's a whole lot of history with having to do some form of retrofitting or upgrades. That's just part of the business of having generation.

MR. HAKE: Yeah. So I guess what I would add here is, putting my personal opinion hat on, I don't know that AES Clean Energy, we have not gone through a detailed analysis to say X number of our plants will be decommissioned. What I would say, though, is I think it's a very valid and real concern, especially for plants that are older, right? The older the plant, potentially the less ROI we're getting, the more we have to spend on, it begins to not make sense very quickly. So I -- so I appreciate the question. I think it's a -- it's a really good point to make.

MS. JONES: This is Rhonda's, not Invenergy's. I feel that the -- there's still a very strong argument that the IBRs, even the ones that are, you know, quite seasoned, still have an effective role in grid stability, even not being upgraded to the latest and greatest, that they still play a role. And it would be an interesting argument to hear that them being prematurely decommissioned is better for the grid than them staying on and still helping grid reliability, and I just -- I don't really -- I don't -- I don't really see that case.

Definitely the goal is to optimize performance. Definitely that's an ever-changing responsibility based on grid conditions and dynamics, and you should be in a position to optimize performance and how we're kind of defining that now. But I do still feel there is a stronger case, personally, for proving with data that the role that they serve now on the grid is still very helpful overall to reliability versus not being on it. And with some of the queue positions getting backed up and things taking longer to come online, you can't even say, oh yeah, you're out of here, we have somebody ready to replace you right away. The timing doesn't happen exactly like that. So I appreciate the question.

MR. HAKE: And I would agree with, I think, your premise at a high level. The one thing that I'd leaned back onto a comment that I made earlier is, if the grid operators don't understand how that unit is going to react and actually, you know, how during disturbances or during extreme situations on the system what they can expect to be on or off, there may be negative reliability impacts in those areas as opposed to the steady state issue. So that -- all of that needs to be taken into account. And if an entity chooses to not want to look into that issue, I'm not sure that that's a benefit to reliability for them to hang on just for the sake of hanging on, but I do think that somebody does need to analyze that information.

MR. HAKE: Yeah, I agree, and if I could just offer one mitigating factor. I think that, at least for existing BES units, they would already comply with

PRC-020. So we're not talking about units that are totally off the wall doing crazy things, right?

MS. JONES: Right.

MR. MAJUMDER: Rajat from GE Vernova. So, Howard, question to you. What's the basis of that you were saying that it's not being done, that somebody's not looking into it, when you say the grid operator needs to know what the unit are going to be doing? I mean, isn't it something we are doing already? So why is it being raised as a matter of concern? There are always going to be outlier where the models did not keep up to the actual equipment behavior. And I did not made the statement when we were working in Appendix G of 2800, so I'm bringing it up again. And there has been some statement made that, oh, well, the models are not good. It's not true. Yes, there has been some exception, but rest of the thing, we are all going through Mod 26 and 27, not every other 26 and 27 shows models are matched.

MR. GUGEL: Yeah.

MR. MAJUMDER: So I'm just trying to sense your concern that when you say that it's a reliability risk, flagging that grid operator does not know how these equipments are going to behave.

MR. GUGEL: So I would point to all of the reports that we have on our system. If you look at each of the events that we've analyzed, we pointed back to grid components that reacted in ways that both the reliability coordinator, the transmission operator, and, in many instances, the generator owner/operator did not expect that to happen. After a root cause analysis was done into that, it was found out that there were maybe some additional controls that were installed on the plant that nobody was aware of, or that the generator owner might've been aware of it, but that information had not been translated to the transmission operator or to the reliability coordinator.

So if you -- if you look through all of -- that's why I'm saying that our experience has been, over the last seven to eight years, that disturbances that are occurring on the grid are happening, and the reliability coordinator and the transmission operator is seeing things happen that they're not expecting. And it's because these units, each time they come up, they're behaving in a little bit of a different way than they have in the past. So we'll fix -- what's happening is we'll fix one problem, you know, let's, let's take Blue Cut Fire. We had an issue with three phase fault, bunch of units tripped out, found out that that was an issue with sampling on frequency, got that fixed. A year later, had a bunch of other units trip out on a single line-to-ground fault for a different control system that was in the same plant.

Until we do a deep dive and try to figure out what those scenarios are, we're going to continue to see grid perturbations that occur that are reliability concerns that are small at this point, but when we get to a 50-percent penetration, they're not going to be small anymore, is my concern.

MR. MAJUMDER: Yeah.

MR. GUGEL: So that's why I'm raising --

MR. MAJUMDER: I fully agree with that, and that's what I'm saying, that things has happened and even there were repeat offender. I know that. I mean, Odessa even not specifying anything when ERCOT went ahead, and, you know, published the report, there were plans/manufacturer who made a commitment to fix it, and the second one came up and it was saying that it's there. So I fully understand.

But at the same time, let's not -- I'm just trying to say that let's not think -- that thing has also happened with synchronous machine. There are so many synchronous machine out in the -- in the field, but the excitation system model, if you look at it, there's still rotation, you know, the slow rotary excitation system. In real field, it's completely different. So the issue is not only in IBR, so let's not think that how it's going to be -- I'm not at all undermining the necessity that you are establishing. I fully agree with that, but I'm just trying to say that please let us not flag IBR fleets specifically for this issue. This issue exists.

MR. GUGEL: So my qualification was just the specific question that you asked me: Why, Howard, are you calling out and saying that grid operators don't know what's going on, and so that's why I was pointing to the reports there. Do we see issues happening with synchronous generators? Yes. Have we modified generation standards over the years to basically react to that? Yes. But from a synchronous generator standpoint, a lot of the technology that's behind that and the basis behind it is something that's been around for 50, 60 years. We've had the ability to kind of go through that, understand the issues, and basically know how that reacts on the grid.

We're now introducing some new components at a fascinating, incredibly fast rate of equipment that has some great reliability benefits. It has a potential for that, but also has a potential to give us some unknowns and put us in unknown operating states.

MR. YEUNG: So, Howard --

MR. GUGEL: We need to be in front of that as opposed to --

MR. YEUNG: Howard, I'm going to interrupt a little bit. I think those are probably basis of the order, you know, so we need to move forward, and, you know, implement the order, so absolutely important arguments, but any more questions about implementation?

MS. CASUSCELLI: We have one online. Is there an effort underway for the design compliance and further performance compliance for PRC-029?

MS. CALDERON: Could you say that again?

MS. CASUSCELLI: I can repeat it. Mentioned in the panel was a technical document. Is there a way -- is there any effort underway for the design compliance and for the performance compliance for PRC-029?

MR. PATEL: Yeah. So I think -- I think that's where I mentioned IEEE 2800.2, where we are trying to put the framework where, you know, the equipment actually gets tested, right? IBR units, individual inverters, the wind turbine generators, we understand their capability. We build the plant model, and then we run the simulations on plant model to verify that the plan will be able to Ride-through what the standard requires. There is no effort at the NERC level.

I think that was my point when I gave all the examples of different PRC standards, right? There is a companion NERC document that shows how to do calculations for 023, 025, 026, et cetera, standards, and I think there is equal need. I'm not advocating here for a companion NERC document to PRC-029, but maybe IEEE 2800.2 can serve that role where, you know, you pick up the framework, put together in that document in compliance with, I'm going to start calling 2900. Maybe it will become true.

(Laughter.)

MS. CALDERON: Well, and to add in on that as well, there's ongoing work within the IRPS and within the RSTC work tackling those types of engineering questions. They've had power plant model validation guidelines put out. There's ongoing discussions within those groups, and it seems like an opportune place to bring those up. When it comes to performance, it's really just did it or did it not meet the criteria based off of the measured data. So there'll be a pretty big distinction between those two and how you approach compliance with those.

MR. YEUNG: Any more questions? Any more questions on the internet or Slido? Todd, do you have a question or do you have a comment?

MR. BENNETT: I don't think I have a question or necessarily a comment. I wasn't seeing it either in the room, and, Amy, are we wrapped up online?

(Nonaudible response.)

MR. BENNETT: Okay. So with that, thank you to our panel. Very in-depth discussion here. Many thanks to you. So anyway, how about a round of applause? That's our last panel of this Technical Committee.

(Applause.)

MR. BENNETT: And why don't we get back together here in 15 minutes, and we will review some Slido polls and have some additional polls on PRC-2900.

(Break.)

MR. BENNETT: Okay. So it looks like we're getting ready to start back up here for our last session of the Technical Conference today. I think this should go fairly quickly, but we have three questions to poll to all the participants through Slido, so if you need to, go ahead and join back in on there. I don't know if we can put the QR code back up here real quick just in case anybody needs to join. I'm not sure, but I believe -- yes, Amy's going to have three questions here, and here's the results of our -- of our previous one. Oh, this is actually new, so, okay. So yeah.

MS. CASUSCELLI: Yeah, Todd, that's the new one.

Sorry.

MR. BENNETT: So there's three questions here, and I'm going to hand it over to Amy to kind of lead us through this for the next few minutes.

MS. CASUSCELLI: All right. Yeah, thanks Todd. So as Todd mentioned earlier, you know, we have a series of questions. I believe there's three of them, and, you know, this is not a formal voting mechanism. This is just meant to inform the Standards Committee members' decisions in the next couple of days here on the path forward for all of the things that we've been talking about for the last day and a half.

So for this initial question here, based on the conversation you heard today, and I want to make sure that we differentiate here. This question is related to legacy assets. So what should the PRC-029 voltage and frequency criteria follow that assures reliability assets? So just note that that is for legacy assets. So I'm going to not narrate the entire -- the entire moment here and just let us sit in silence as you all consider and cast your votes.

(Slido voting.)

MS. CASUSCELLI: All right. So I think that we've pretty well slowed down with our votes cast, so looks like we've got an overwhelming response for that question. Thanks for -- everybody, for your input. I think we can move on to the next question.

All right. So this question is the -- identical, with the exception of this is for assets being brought online in the future. So only two options for this one, and this is future assets.

(Slido voting.)

MS. CASUSCELLI: Oh, okay. So I think the -- for those of you who are looking on the screen here in the room, the bottom option is cut off, but it says, "adopt voltage and frequency bands proposed in IEEE 2800."

(Continued Slido voting.)

MS. CASUSCELLI: All right. So it looks like we have a -- an overwhelming opinion on that one as well. So with that, I think we can -- we're ready to move on to our next question, and this one is related to the implementation plans.

UNIDENTIFIED SPEAKER: Amy, I don't think we have a presentation for this. Are we putting the question in front of it?

MS. CASUSCELLI: Okay. Hold on.

(Brief pause.)

MS. CASUSCELLI: All right. It's coming. I see it in Slido. There we go. All right. So regarding the implementation for these new standards, in 25 words or less, what should NERC provide more information on to assist industry in preparation? I don't think there's any penalty for going over 25 words, but --

(Off mic comment.)

MS. CASUSCELLI: Oh, really? Oh, it does cap. Okay. Okay.

(Slido voting.)

MS. CALDERON: All right. Just a quick point of clarity that, of course, that is 25 characters or less. What we're going to do here is when this closes, we're going to close it and reopen it with that image removed, just so it's easier to see for -- at least for the folks in the room.

(Continued Slido voting.)

MS. CASUSCELLI: All right. I think we've seen a slowdown in responses, so I think we're ready to close it. And if you could, yeah, Jamie, like you said, display the image, I think that would be helpful for folks.

(Brief pause.)

MR. BENNETT: Okay. So while we wait on the results to be posted up here on the screen for everyone to see, at least something that jumped out at me on this was the term "compliance guidance." So it was larger in the middle. That that means it got mentioned a bit more than some of the other items. So, you know, one thing that I am glad about on compliance guidance is there's not only one path. So there's multiple organizations that have been approved to put documents like that together and can be endorsed by NERC. So o it's -- I don't think that's a deviation from the past, so I think there's some real promise there. Another word that I saw that wasn't quite as big as "compliance guidance," but it makes me think of certainty, but it was "implementation timing," you know, what to expect.

So with that, maybe I can kind of segue into the next part of what to expect after this technical conference concludes. So after we wrap up today, we'll take the feedback from these polls from the -- from the conversations over the last couple days, and the NERC Standards Committee, in conjunction with members from NERC as well as some of the Drafting Team members that are available, we'll get together and start redlining the standard based on what we've learned. So there's not an infinite time to do that. It's pretty compressed. So I would expect, you know, that to probably conclude by the end of next week, you know. So it's going to be a busy next six or seven days for a group of people, but at that time, I believe that we'll be able to have a revised standard that captures maybe a slightly different path forward. But then also part of that is an implementation plan that is with that, and I believe that will help with the certainty.

You know, both of these documents, I can't for foretell what will be on them at this current point in time. But they will be out there and I believe that the implementation plan will help with that, what to expect, and, based on certain scenarios, what companies should try to plan on, given that the standard's approved. If it's not approved, that's a whole different -- that's a different story. That's not our conversation for today. So anyway, I think that that might help with what to approve and implementation guidance. Based on the conversations that I've heard today, and some of the -- you know, the history with the multiple ballots going out to industry and struggling to find consensus, this does seem like an ideal candidate for some type of implementation guidance.

So with this in front of us here, these are the most popular feedback words from today. So there's "compliance guidance" in this poll, "timelines," "we've anticipated timeline," "priorities." So there's a lot of things that we've already touched on, but then I see several words up there that we need to consider over the next week. So with that, I don't have anything else to add, but are there any other questions in here about the path forward and what to expect over the next few weeks?

Maybe something I can -- that I didn't touch on is, I believe the draft standard as well as the implementation plan posting to industry, we don't have a specific date yet, but be on the lookout for mid-September, so somewhere in there. We still have some processes to make it through for quality review and drafting. After that, it also has not been agreed upon the amount of time for comment and ballot. However, we do have to have it concluded by the 30th, so the end of the month. So one thing that I'm trying to commit to is to give industry as much time as we possibly can but still get the best product that we can with the limited time that we have. So with that, any parting questions on this?

MS. JONES: (Off mic question.)

MR. BENNETT: So the question is balloting will happen this month. So that's what I'm -- that's what I'm hearing. This will be posted for ballot in mid-September, and then the timeline has not been released, whether that will be five days, seven days, 10 days, but, you know, somewhere kind of in there, but we have to have it concluded by the 30th.

MS. JONES: (Off mic question.)

MR. BENNETT: So the question is about comments previously provided. So the previous ballot is what you're referring?

MS. JONES: (Off mic comment.)

MR. BENNETT: Oh, for this conference.

(Off mic comments.)

MS. JONES: So for the comments that were provided or testimonies to support this Technical Conference, if the team that's working on drafting the new ballot decide to use some of that or borrow from it, if they borrow it, will there be citations related to who they borrowed it from?

MR. BENNETT: So on that, and my NERC friends here, correct me if I'm wrong, I have not heard any response to responding to the comments that were provided to support this Technical Conference. The comments and testimony that was provided to help with this Technical Conference was for learning, for the building of a -- an official record of what happened with this for, you know, a potential future filing with FERC, but then also to provide some metrics and inform and to help us develop the agenda for today as well as some of the follow-up questions for the agenda today. So that's what that comment -- that's what those formal comments were used for at this point.

MS. JONES: Okay. So they won't be probably used with the Drafting Team. I thought they would possibly be.

MS. CALDERON: Yeah. So the next steps is with the Standards Committee. We actually do have the Drafting Team and NERC staff to make revisions to the standard, working together, putting together the official memo. All of it's going to be used for the record of development as well for the filings, so decisions made that were based off of information that was provided. We got a lot of substantial information from the OEM, will be used to substantiate decisions made in the filing with FERC.

MS. JONES: Thank you.

MR. BENNETT: Okay. Thank you, Jamie. I'm looking around the room. I don't see any final questions here. Okay. With that -- oops, sorry. We have one more.

MR. CONWAY: Yeah, Kevin Conway, Western Power Pool. More of a comment about this forum. We've talked, I think, in the hallway quite a bit about it.

It would be nice if through our standards process we engage in this type of process earlier, right? Too many times, just like in this case here, we're already down the road so far. There's no course corrections of any major impact that we can make, but our -- with the intent of trying to accelerate the development of these standards based on Board direction or FERC direction, these are helpful and these move the Drafting Team faster, farther, and more effectively down the road.

MS. CALDERON: -- going to speak on your behalf, Soo Jin, on just everything you've been doing for getting more of these, so I'll let you go ahead.

MS. KIM: Probably to Levetra and Tiffany and Kelsey's chagrin, I do think we're going to have a lot more technical conferences, not just for the next couple of milestones, but as you all know, there are several other projects on the horizon. We have an extreme hot and cold weather temperature project that is another directive that is due in December. There's a webinar next Tuesday, so I'm going to put a little plug in for that for all of the utility stakeholders who are participating in that. I think the team has made some tremendous progress. I think they would like to present that. They're going to borrow some of the tools from today that was very effective, and so they're going to try to solicit a lot of technical input next Tuesday for extreme hot, cold -- hot and cold temperatures. I do believe for the next directives after that, as many of you know, we have some directives with regards to extreme cold weather. That one is also probably going to require some type of technical input.

We will have more of these events. We did commit to doing that. I cannot promise that every project will have that. But for some of the major projects that we see on the horizon, high-priority projects, things that require a lot of coordination where there's major gaps in information that the team just did not have at its fingertips, I do think that these events are much more fruitful than I think many people imagine when we first started down this path.

So thank you again for your participation. I will commit that the Department is going to not just look at this just from the standards perspective, but also on the engineering side. We have talked about doing more technical conferences generally, even before we get to some of the standards development steps.

MR. BENNETT: Okay. Thank you Soo Jin. And I just wanted to say, I'm going to have -- I'm going to ask Sue to say a few words here at the end, but I just wanted to mention to everybody that, you know, this was kind of a first of its kind, so thanks for bearing with this as we made it through this. We did learn that some things worked really well, some probably could've worked a little better, but it sounds like there'll be more of this, and this was a learning event for everybody, so thank you. And Sue, do you have any parting words?

MS. KELLY: I do. I have been designated to give the benediction.

(Laughter.)

MS. KELLY: So on behalf of the Board, I want to thank everyone who participated in this technical conference, both in person and online. It has been a content rich experience, especially for, you know, a laywoman like me, and I think I've learned a lot. I also know a lot more about what I don't know which is, I guess, also good. I think we all have a better idea of some of the pressure points and the fault lines regarding the current draft of this standard, and I think we have some ideas about how we might be able to address those, which is great.

I want to thank NERC staff and the Standards Committee, not only for what you've already done, but the mission which you are about to undertake, effort you're going to have to undertake to prepare the next draft of this standard for ballot in an extremely accelerated time frame as Todd just reviewed with you. As Soo Jin noted this morning, we're operating under tight time frames that were set both by FERC and by Rule 321 if you care to go review that. We have to finish the balloting by September 30th, so everyone involved is going to need to put their shoulder to the wheel to make sure this happens.

And we do need to get it done. I would note that FERC has instructed us to get it done by a date certain, and the Board intends -- we're going to do that, but the need to finish this effort goes well beyond the administrative imperatives that we face. NERC produced its first reliability guideline on these issues back in 2018. I was reviewing that this morning. This drafting project commenced in 2020. As Howard pointed out this morning, we already have hours in some regions where energy from embroider-based resources are producing virtually all the energy on the grid. And the projections are that by the end of the decade, it could be 50 percent of our capacity might be IBR based. If the lead time estimates for the needed software and hardware changes that we heard about from the OEMs yesterday are indeed accurate, then we need to move swiftly now to establish new standards that will ensure reliability going forward as we have many more of these devices on our grid.

So again, thank you for your time and attention so far, and thank you for the additional work that you are going to undertake to bring us to the finish line by September 30th, and may you all have safe travel home. Thank you.

(Applause.)

MR. BENNETT: Okay. So with that, I believe that we are adjourned for the day, so thanks again for everyone's participation. Safe travels, and more to come.

(Whereupon, at 3:23 p.m., the Technical Conference was concluded.)

CERTIFICATE OF TRANSCRIBER

I, Charlene Williamson, do hereby certify that, to the best of my knowledge and belief, the attached transcript is a true and accurate transcription of the indicated audio recording.

I further certify that I am neither attorney nor counsel for nor related nor employed by any of the parties to the action; further, that I am not a relative or employee of any attorney or counsel employed by the parties hereto or financially interested in this action.

9/9/2024

DATE

Charlene Williamson

Charlene Williamson
TRANSCRIBER

WORD INDEX

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit H

Summary of Issues and Alternatives Considered Memo

To: NERC Board of Trustees and Stakeholders

From: NERC Staff and Representatives from the Standards Committee

Re: Summary of Issues and Alternatives Considered, Proposed Reliability Standard PRC-029-1 (Frequency and Voltage Ride-through Requirements for Inverter-based Resources)

Date: September 24, 2024

In Order No. 901, the Federal Energy Regulatory Commission ("FERC") directed the development of new or revised Reliability Standards to address certain reliability issues related to inverter-based resources ("IBRs"), including IBR ride-through performance.[1] To address the IBR ride-through directives, Project 2020-02 Modifications to PRC-024-4 initiated development of proposed Reliability Standard PRC-029-1 (Frequency and Voltage Ride-through Requirements for Inverter-based Resources). However, proposed Reliability Standard PRC-029-1 has failed to pass ballot through the usual standard development process.

Section 321 of the NERC Rules of Procedure allows the NERC Board of Trustees to take special actions when a ballot pool has failed to approve a proposed Reliability Standard that contains a provision to adequately address a specific matter identified in a directive issued by an Applicable Governmental Authority. The NERC Board of Trustees took such action for the proposed PRC-029-1 standard at its August 2024 meeting.[2]

Consistent with Section 321.2 of the NERC Rules of Procedure, the Standards Committee and NERC staff convened a technical conference from September 4-5, 2024 to discuss the issues surrounding the FERC Order No. 901 directives, including whether or not the proposed Reliability Standard PRC-029-1 is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified. This memorandum discusses the issues, an analysis of alternatives considered, and other appropriate matters.

Background

On October 19, 2023, the Commission issued Order No. 901 directing the development of new or revised Reliability Standards to address reliability issues associated with the growth of IBRs on the Bulk-Power

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1 *Reliability Standards to Address Inverter-Based Resources*, Order No. 901, 185 FERC ¶ 61,042, Docket No. RM22-12-000 (Oct. 19, 2023) [hereinafter Order No. 901]. Available here.

2 NERC Board of Trustees, Minutes of the August 15, 2024, available here.

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Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

System.[3] The Commission directed NERC to develop new or revised Reliability Standards addressing IBR reliability issues as follows:

1) IBR disturbance monitoring data sharing and post-event performance validation[4] and ride-through performance requirements[5] by November 4, 2024;
2) IBR data and model validation[6] by November 4, 2025; and
3) planning and operational studies[7] for IBRs by November 4, 2026.

The Commission also directed NERC to develop and submit a work plan to develop new and revised Reliability Standards to address these issues in accordance with the specified timeframe.[8]

On January 17, 2024, NERC submitted its Order No. 901 Work Plan,[9] which consists of key milestones to meet the Commission's directives by the filing deadlines mentioned above. **Milestone 2**, in progress, focuses on the development of Reliability Standards to address disturbance monitoring, performance-based ride-through requirements and post-event performance validation for registered IBRs by November 4, 2024.

The Reliability Standards being proposed to address **Milestone 2** of FERC Order 901 are being developed through the following projects:

- Project 2020-02 Modifications to PRC-024 (Generator Ride-through),
- Project 2021-04 Modifications to PRC-002,
- Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues

As of this writing, Projects 2021-04 and 2023-02 are on track for timely completion through the usual NERC standard development process. Project 2020-02, addressing generator ride-through directives from Order No. 901, is the subject of special Board action under Section 321.

Specifically, proposed Reliability Standard PRC-029-1 (Frequency and Voltage Ride-through Requirements for Inverter-based Resources) is a draft standard designed to establish capability-based and performance-based ride-through requirements for IBRs during grid disturbances, to address the Commission directives from Order No. 901. The draft standard failed to achieve consensus from the Registered Ballot Body over

3 *See Order No. 901, supra,* at PP 229.

4 *See id.* at PP 66-109 (discussing directives related to data sharing requirements).

5 *See id.* at PP 178-211 (discussing directives related to performance requirements).

6 *See id.* at PP 110-161 (discussing directives related to data and model validation requirements).

7 *See id.* at PP 162-177 (discussing directives related to planning and operational studies requirements).

8 *See id.* at P 222.

9 Informational Filing of the North American Electric Reliability Corporation Regarding the Development of Reliability Standards Responsive to Order No. 901, (Docket No. RM22-12-000) (2024) [hereinafter Order No. 901 Work Plan].

multiple ballots, the latest of which occurred between August 2, 2024 to August 12, 2024. This called into question whether development would be completed by FERC's filing deadline of November 4, 2024.

As a result, the NERC Board of Trustees initiated the use of Section 321 at its August 15, 2024 meeting. Under this special authority, the Board directed the Standards Committee to work with NERC Staff to convene a technical conference to gather input from industry to address the outstanding issues and revise PRC-029-1. This memorandum describes the issues that led to the technical conference convening and the alternative solutions that were considered. The proposed PRC-029-1 standard has been revised using input from the technical conference and is submitted for stakeholder ballot. This process must be completed within 45 days of being initiated, which is September 30, 2024. If the re-balloted proposed Reliability Standard achieves at least an affirmative 60% majority vote of the weighted Segment votes cast, then the Board may consider it for adoption under Section 321.

Order No. 901 Directives for Ride-through

In Order No. 901, the Commission cites to multiple event reports as the reason that IBRs should have Reliability Standards for ride-through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults.[10] Below you will find the Commission's specific directives on how IBRs should ride-through disturbances and how exceptions should be applied to certain IBRs. Finding consensus around these directives were a part of the main issues addressed during the technical conference.

> "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system disturbances and that permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults. The new or modified Reliability Standards must require registered IBRs to continue to inject current and perform frequency support during a Bulk-Power System disturbance. Any new or modified Reliability Standard must also require registered IBR generator owners and operators to prohibit momentary cessation in the no-trip zone during disturbances. NERC must submit new or modified Reliability Standards that establish IBR performance requirements, including requirements addressing frequency and voltage ride through, post-disturbance ramp rates, phase lock loop synchronization, and other known causes of IBR tripping or momentary cessation."[11]

> "Therefore, we direct NERC through its standard development process to determine whether the new or modified Reliability Standards should provide for a limited and documented exemption for certain registered IBRs from voltage ride-through performance requirements. Any such exemption should be only for voltage ride-through performance for those existing IBRs that are unable to

10 See Order No. 901 at PP 190.

11 See *id.*

modify their coordinated protection and control settings to meet the requirements without physical modification of the IBRs' equipment."[12]

Summary of Issues and Alternatives Considered

The technical conference took place on September 4-5, 2024, and focused on unresolved issues raised by stakeholders raised during the PRC-029-1 comment periods. Specifically, the technical conference focused on: (1) the proposed definition of "Ride-through"; (2) the proposed criteria for frequency ride-through performance; and (3) the feasibility of allowing hardware-based exemptions from the frequency ride-through requirements, similar to the voltage ride-through exemption FERC directed NERC to consider in Order No. 901.[13] These issues, and the alternatives considered, are discussed below.

Ride-Through Definition

The most recent Standard Authorization Request for Project 2020-02 included direction to the drafting team to define the term "ride-through" as necessary. During the development of **Milestone 2** projects, a definition for "ride-through" was considered by the drafting teams of both PRC-029 and PRC-030 as both Reliability Standards leverage the term to refer to acceptable performance criteria outlined in PRC-029. Per the Standards Process Manual (NERC Rules of Procedure Appendix 3A), definitions themselves may not include statements of performance requirements. As such, the specific performance requirements and measures to demonstrate ride-through are to be found within the Requirements and Attachments of PRC-029-1. References to "Ride-through criteria" in PRC-030-1, allow for those additional analytics to include further evaluations with PRC-029-1 Ride-through performance requirements as appropriate while preventing duplication of those performance requirements in different Reliability Standards.

Comments from Draft 3 of PRC-029-1 concerning the proposed definition of "Ride-through" were reviewed. In the previously proposed definition, many stakeholders argued that the proposed definition was too broad and ambiguous, particularly with the inclusion of phrases like "entire" and "in its entirety." Those stakeholders recommended revisions to clarify the definition and ensure it aligns better with IEEE Std 2800™, IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems.[14] The Draft 3 proposed definition of "Ride-through" was discussed at the technical conference and presented on by a member of the original drafting team.[15] The Draft 3 definition was presented as follows: "The entire plant/facility remaining connected to the Bulk Power System and continuing in its entirety to operate through System Disturbances."

As part of the presentation, ten (10) alternative definitions were presented as proposed by commenters during the previous rounds of ballot and formal comment. After the presentation, four (4) of the most

[12] See Order No 901 at PP 193.

[13] See Order No 901 at PP 199.

[14] Hereinafter referred to as "IEEE 2800-2022".

[15] See "Outlining Objectives of a Ride-through Definition" of posted Standards Committee and NERC Ride-through Technical Conference material; page 94/129.

distinct definitions were opened to technical conference attendees as a straw poll to gauge overall industry preference. When asked "Which of the following proposed definitions for Ride-through do you think is most correct?":

- 68% voted in favor of the "Ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified.";
- 16% voted in favor of "The plant/facility remaining connected to the Bulk Power System and continuing to operate through System Disturbances as defined in applicable reliability standards.";
- 12% voted in favor of "The entire plant/facility remaining connected to the Bulk Power System and continuing in its entirety to operate through System Disturbances."; and
- 4% voted in favor of "The plant/facility shall remain connected and in service, maintaining the pre-disturbance equipment configuration in operation, throughout the entirety of the system disturbance and recovery."

Following the technical conference, NERC staff, Standards Committee representatives, some members of the drafting team, and FERC staff met to discuss the results of the straw poll as well as previously reviewed material. Based on that discussion, language in the preferred definition such as "ability to withstand", "defined limits" and "as specified" were unclear and were inherently challenging for use in a definition that must be leveraged by multiple Reliability Standards. It was determined that the final draft would proceed with the 2nd most preferred definition, with slight modifications to remove usage of other defined terms that had an embedded usage of the Bulk Electric System defined term. The final definition as proposed in Draft 4 of PRC-029-1 is as follows: "The plant/facility remains connected and continues to operate through voltage or frequency system disturbances."

Proposed Criteria for Frequency Ride-Through Performance

As described in the Project 2020-02 Standard Authorization Request and assigned directives from Order No. 901, the drafting team was tasked with developing new or modified Reliability Standards to assure a performance-based approach to generator ride-through. This scope included requirements that generating resources shall ride-through grid disturbances and include quantitative measures on expectations for ride-through that address all possible causes of tripping and power reductions from generating resources (particularly generator, turbine, inverter, and all plant-level protection and controls).

The proposed new Reliability Standard PRC-029-1 requires generator owners of IBR to both design and operate their IBR plants to ride-through voltage and frequency system disturbances. Requirement R3 and Attachment 2 of PRC-029-1 define the quantitative frequency ride-through criteria by use of measured frequency magnitude and time duration of sustaining that magnitude for all conditions. As discussed during the development of PRC-029-1, many stakeholders commented in previous ballots a preference to leverage those quantitative values as currently established in IEEE 2800-2022.

Frequency ride-through criteria was a prominent discussion of the technical conference. Members of the drafting team presented on the decisions made during the development of these criteria during the technical conference.[16] The presentation explained that the voltage and frequency ride-through zones

[16] See "Review of Voltage and Frequency Ride-through Criteria in PRC-029-1" of posted Standards Committee and NERC Ride-through Technical Conference material; page 47/129.

proposed in Draft 3 of the standard were based on the IEEE 2800-2022 no-trip zones and were established in view of drafting team member experience with frequency excursions in planning and operations. The drafting team also stated the proposed frequency criteria were reasonable and were practical limits of IBR frequency tolerances, inclusive of adequate margins for worst-case conditions.

Following the presentation by the drafting team, NERC staff presented on voltage and frequency Ride-through evaluations taken from recent NERC disturbance reports and the report results from the March 2023 Level 2 Alert.[17] The NERC presentation stressed balancing Bulk Power System needs with reasonable criteria that account for technical capabilities of currently designed equipment. NERC also highlighted a continued need to coordinate messaging during the design and interconnection phases of new IBR to have protection and controller equipment set in accordance with the hardware capability of the IBR rather than only in relation to minimum values established in NERC Reliability Standards.

Two panels regarding frequency criteria were held during the technical conference. The first panel included representatives of various IBR original equipment manufacturers, and the second panel included other members of industry.[18] Discussions from both panels highlighted the following key issues:[19]

- Many IBR designed before 2014 would be unable to meet frequency Ride-through magnitude and duration criteria proposed in Attachment 2 of Draft 3. It was estimated by one panelist that approximately 20 GW of installed capacity would not be able to meet the criteria, indicating significant challenges for legacy IBR without substantial hardware replacement and redesign.
- Many IBR had not been designed to meet a rate of change of frequency (RoCoF) of 5 Hz per second. Of concern from the panelist was the technical basis for determining the need for a 5 Hz RoCoF did not include a study or more thorough evaluation of potential system strength benefits and that different parts of the Bulk Power System have not been demonstrated to require it.
- Recent event reports presented by NERC were all related to voltage excursions, potentially indicating that frequency-based disturbances were less likely to occur. Some panelists contended that this potential lower likelihood of experiencing a frequency event did not align with the expansion of frequency criteria beyond those currently established in IEEE 2800-2022.

After the panels of this topic, two straw polls were opened for attendees of the Ride-through technical conference to provide their feedback for consideration regarding “legacy” IBR and future IBR.

When attendees were asked “Based on the conversation you heard today from our panels, for legacy assets, what should PRC-029 voltage and frequency criteria follow that assures reliability and is reasonable for industry?”:

- 64% voted in favor of “Maintain PRC-024 criteria for IBR”;

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17 See “Review of Voltage and Frequency Ride-through” of posted Standards Committee and NERC Ride-through Technical Conference material; page 67/129.

18 See “Panel Discussion: Original Equipment Manufacturer Perspectives on Voltage and Frequency Ride-through Criteria” of posted Standards Committee and NERC Ride-through Technical Conference material; pages 85/129 and 86/129.

19 See Day 1 Recording and Transcript of the Standards Committee & NERC Ride-through Technical Conference; Project 2020-02 Modifications to PRC-024 (Generator Ride-through) Related Files; posted September 18, 2024.

- 29% voted in favor of "Adopt voltage and frequency bands proposed in IEEE 2800-2022"; and
- 6% voted in favor of "Retain currently proposed PRC-029 criteria".

When attendees were asked "Based on the conversation you heard today from our panels, for assets being brought online in the future, what should PRC-029 voltage & frequency criteria follow that assures reliability and is reasonable for industry?":

- 90% voted in favor of "Adopt voltage and frequency bands proposed in IEEE 2800-2022"; and
- 10% voted in favor of "Retain currently proposed PRC-029 criteria".

Following the technical conference, NERC staff, Standards Committee representatives, some members of the drafting team, and FERC staff met to discuss the results of the straw polls as well as previously reviewed material. The team discussed that the term "legacy assets", as used during the technical conference, aligned with the date for seeking potential exemption within PRC-029-1; meaning those IBR that were "in-service" by the effective date of PRC-029-1. While respondents at the technical conference did vote more favorably to retaining existing PRC-024 criteria for legacy assets, other information submitted by commenters and highlighted during the panel of original equipment manufacturers, indicated that a significant majority of IBR have been designed to meet IEEE 2800-2022 values.[20, 21]

Additional information provided during the NERC staff presentation[22] identified that many IBR were still being designed and installed without setting their protection and controls in accordance with their physical capabilities. Due to a concern of lowering the bar of performance by requiring that IBR perform less than what the significant majority of IBR are being designed and manufactured to, it was determined that the proposed standard should not align with previous PRC-024-3 criteria.

Based on the more clearly understood hardware-based capability limitation established due to manufacture design for a significant amount of installed IBR, there was a reliability concern to proceed with Draft 3 PRC-029-1 frequency criteria as that same amount of IBR could necessitate disconnection and retrofitting in order to comply. It was also identified that the potential disconnection of a large amount of installed IBR capacity did not substantially outweigh unstudied reliability benefits potentially resulting from setting frequency ride-through bands wider than those established in IEEE 2800-2022 and overwhelmingly identified by manufacturers during our comment review when designing IBR throughout the past decade. Due to these reliability concerns, the frequency criteria in Attachment 2 of the draft has been adjusted to align with those values in IEEE 2800-2022.

Feasibility of Hardware-Based Exemptions from Frequency Ride-Through Requirements

Potential hardware-based exemptions were discussed during each formal comment period of PRC-029-1, with a significant majority of commenters supporting some exemptions from frequency ride-through

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20 See Industry Submitted Comments for the Standards Committee & NERC Ride-through Technical Conference; [Project 2020-02 Modifications to PRC-024 (Generator Ride-through) Related Files]; posted September 2024.

21 See Day 1 Recording and Transcript of the Standards Committee & NERC Ride-through Technical Conference; [Project 2020-02 Modifications to PRC-024 (Generator Ride-through) Related Files]; posted September 18, 2024.

22 See "Review of Voltage and Frequency Ride-through" of posted [Standards Committee and NERC Ride-through Technical Conference material]; page 67/129.

criteria for legacy IBR. The drafting team and industry were advised that Order No. 901 only included and only allowed for exemptions of voltage ride-through performance requirements, based on the following discussion of allowable exemptions within the order:

> "Therefore, we direct NERC through its standard development process to determine whether the new or modified Reliability Standards should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements."[23]
>
> "Further, we direct NERC to ensure that any such exemption would be applicable for only existing equipment that is unable to meet voltage ride-through performance. When such existing equipment is replaced, the exemption would no longer apply, and the new equipment must comply with the appropriate IBR performance requirements specified in the Reliability Standards (e.g., voltage and frequency ride through, phase lock loop, ramp rates, etc.)." [24]

While the order spoke only to exemptions from voltage ride-through requirements and was silent regarding any exemptions for frequency ride-through criteria, industry continued to identify that there was a need to include such exemptions in PRC-029-1. It was determined that the details shared leading up to and during the technical conference provided clarity as well as a more substantiated basis for why hardware-based exemptions of frequency ride-through criteria was needed.

Prior to the technical conference, NERC solicited comments from industry as well as original equipment manufacturers.[25] In particular, any information on hardware-based limitations that would prevent IBR from meeting the proposed frequency criteria within PRC-029-1 was requested. 21 individual comments were received including six (6) from different original equipment manufacturers of IBR. NERC and representatives from the Standards Committee reviewed the submitted material and confirmed that IBR are being designed by original equipment manufacturers to be able to meet those voltage and frequency ride-through curves established in IEEE 2800-2022. As Draft 3 of PRC-029-1 proposed frequency criteria were beyond those established in IEEE 2800-2022, there was a concern that IBR would not be able to meet those proposed frequency criteria as IBR capability limits were hardware-based and inherent to a manufacturer's design.

While many comments received during the formal comment periods stressed a desire to align PRC-029-1 with IEEE 2800-2022, there was little differentiation between comments that sought to leverage other industry volunteer guidelines that have been significantly adopted with those comments that sought exemptions due to the fact that manufacturers are designing IBR capabilities to the IEEE 2800-2022 values. Moreover, comments submitted by manufacturers provided a better understanding and approximation of what percentage of the installed fleets of IBR would be unable to meet PRC-029-1 frequency criteria. While additional information regarding specific amounts of affected IBR is still sought by NERC, from the

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23 *See id*. at P 153.

24 *See id*. at P 153.

25 See Standards Committee and NERC Ride-through Technical Conference; Conference Details; publicly announced August 21, 2024; https://www.nerc.com/pa/Stand/Documents/SC_and_NERC%20Ride-through_Technical_Conference_Details_08212024.pdf

information provided, it appears that a significant percentage of IBR[26] – specifically Type 3 wind turbine facilities – would need to retrofit to avoid noncompliance with PRC-029-1 as proposed in Draft 3.

The technical conference included a panel discussion on frequency exemptions. Panelists discussed various challenges related to legacy IBR, such as difficulties obtaining more detailed information on equipment capabilities; specifically for manufacturers who are no longer in business and for IBR that are no longer supported by the manufacturer. In such instances, additional time and cost would be expected to conduct more detailed capability testing. Other concerns raised included the possibility that manufacturers would not be willing to provide design or hardware limitation documentation should they identify the information to be proprietary information. Other discussions substantiated information received during the solicitation of comments for the conference and provided more clarity as to the alignment of the IEEE 2800-2022 curves with inherent capability limitations.[27]

Following the technical conference, NERC staff, Standards Committee representatives, some members of the drafting team, and FERC staff met to discuss the discussions during the conference as well as previously reviewed material. Based on the more clearly understood hardware-based capability limitation established due to manufacture design for a significant amount of installed IBR, there was a reliability concern to proceed with no potential for hardware-based limitations for frequency criteria, as that same amount of IBR could necessitate disconnection and retrofitting to comply.

It was determined that this potential disconnection of a large amount of installed IBR capacity overwhelmingly indicated a reliability need to allow for a documented and limited set of exemptions for IBR from voltage and frequency ride-through criteria. In light of this reliability concern, Requirement R4 of PRC-029-1 has been modified to allow for a documented, and limited set of exemptions for IBR from frequency criteria. Further modifications were made to allow Generator Owners to exclude information considered to be proprietary from submittals to anyone other than the Compliance Enforcement Authority, to facilitate the sharing of requisite information from manufacturers.

Conclusion

After following the process described in Section 321 of the NERC Rules of Procedure, as directed by the NERC Board of Trustees at the August 15, 2024 meeting, proposed Reliability Standard PRC-029-1 has been revised to: include revised definition for the new proposed term "Ride-through", align frequency ride-through criteria with IEEE 2800-2022 values, allow for a limited documented set of exemptions for hardware-based limitations for frequency ride-through criteria, and to allow Generator Owners to only share information deemed by the original equipment manufacturer as proprietary with the Compliance Enforcement Authority..

These revisions in proposed Reliability Standard PRC-029-1 reflect a fulsome consideration of the technical, reliability, and implementation considerations raised in the underlying development proceeding and during

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[26] Analysis of the data collected through NERC's Level 2 Alert: Industry Recommendation for IBR Performance Issues showed that the number of resources that are not able to meet PRC-029 Draft 3 is approximately double when compared to those same resources ability to comply with the updated criteria in PRC-029 Draft 4 which align with IEEE 2800-2022. Information submitted through the comment period and the technical conference discussions indicated that this ratio would be higher for wind resources, specifically Type 3 wind.

[27] See Day 2 Recording and Transcript of the Standards Committee & NERC Ride-through Technical Conference; Project 2020-02 Modifications to PRC-024 (Generator Ride-through) Related Files; posted September 18, 2024.

the technical conference, with the intent of addressing the Order No. 901 directives in a manner that is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified.

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RELIABILITY CORPORATION

Exhibit I

Standard Drafting Team Roster

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Standard Drafting Team Roster

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

	Name	Entity
Chair	Xiaoyu Wang (Shawn)	Enel North America
Vice Chair	Husam Al-Hadidi	Manitoba Hydro
Members	John B. Anderson	Xcel Energy
	Joel Anthes	Pacific Gas and Electric
	Johnny C. Carlisle	Southern Company Services, Inc
	Rajat Majumder	Ørsted North America
	Robert J. O'Keefe	American Electric Power (AEP)
	Alex Pollock	AMSC
	Ebrahim Rahimi	California ISO
	Fabio Rodriguez	Duke Energy Florida
	Kenneth Silver	8minute Solar Energy
	Ovidiu Vasilachi	Independent Electricity System Operator (IESO)
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