North American Electric Reliability Corporation

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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 STANDARD PRC-030-1

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PRC-030-1

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-030-1 – Unexpected Inverter-Based Resource Event Mitigation.[4] As explained more fully herein, the proposed Reliability Standard would advance the reliability of the Bulk-Power System ("BPS") by requiring Generator Owners to identify, analyze, and mitigate Inverter-Based Resources ("IBR")[5] performance issues. The proposed Reliability Standard would further address the urgent need for Corrective Action Plans to reduce poor IBR ride-through performance from exacerbating system disturbances, as demonstrated by multiple event reports of the last decade, while providing a reasonable period for entities to develop and implement new processes to meet the new requirements.

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

5 On November 4, 2024, in a separate proceeding, NERC submitted for Commission approval a proposed definition for the term Inverter-Based Resource (IBR) for inclusion in the *Glossary of Terms used in NERC Reliability Standards*. The proposed definition for this term is set forth and discussed *infra* in Section V(A).

The proposed Reliability Standard is an integral part of NERC's proposed framework to address IBR performance issues in a comprehensive and holistic manner. As discussed in detail below, proposed Reliability Standard PRC-030-1 is one 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*);
- 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 the proposed definition of Ride-through[6] (*separately filed, concurrently with this petition*); and
- Proposed Reliability Standard PRC-030-1 – Unexpected Inverter-Based Resource Event Mitigation, requiring analysis and mitigation of IBR performance issues.

Proposed Reliability Standard PRC-030-1 would include the processes for conducting analytics and establishing Corrective Action Plans that complement the proposed new Reliability Standard PRC-029-1 addressing ride-through and performance requirements for IBRs. The corresponding new data recording requirements are addressed in the proposed new Reliability Standard PRC-028-1.

The proposed Reliability Standard addressed in this filing is responsive to the Commission's Milestone 2 directive in Order No. 901 that directed NERC to "require generator

[6] On November 4, 2024, in a separate proceeding, NERC submitted for Commission approval a proposed definition for the term Ride-through for inclusion in the *Glossary of Terms used in NERC Reliability Standards*. The proposed definition for this term is set forth and discussed *infra* in Section V(C).

owners to communicate to the relevant planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities the actual post-disturbance ramp rates and the ramp rates to meet expected dispatch levels (i.e., generation-load balance)."[7] As a Milestone 2 standard, proposed PRC-030-1 must be filed with FERC by November 4, 2024.

In compliance with FERC's directive, proposed Reliability Standard PRC-030-1 would require Generator Owners to identify, analyze, and mitigate the post-disturbance performance of IBR. The load balancing component of this directive will be addressed through the evaluation of performance in studies in Milestone 4 projects. Additional work is underway to complete the Order No. 901 Milestone 3 and Milestone 4 directives related to addressing IBR operations and planning issues by their respective deadlines in 2025 and 2026, with an orderly implementation of all new and revised requirements by 2030.

NERC requests that FERC approve the proposed Reliability Standard, 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); and the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (Exhibit F).

As required by Section 39.5(a) of the Commission's regulations,[8] this petition presents the technical basis and purpose of the proposed Reliability Standard, a summary of the development history (Exhibit G), and a demonstration that the proposed Reliability Standard meets the criteria identified by FERC in Order No. 672[9] (Exhibit C). The NERC Board of Trustees adopted the proposed Reliability Standard on October 8, 2024.

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[7] Order No. 901 at P 208.

[8] 18 C.F.R. § 39.5(a).

[9] *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).

I. SUMMARY

NERC initiated Project 2023-02, Analysis and Mitigation of BES Inverter-Based Resource Performance Issues in response to multiple NERC disturbance reports,[10] including the Odessa disturbance report,[11] that identified the undesired performance of BPS-connected IBR during grid faults and detailed the systemic and significant BPS reliability risks that this undesired performance causes. While under development, FERC issued Order No. 901 that directed the development of new or modified Reliability Standards, including 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. 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: Project 2020-02 Modifications to PRC-024 (Generation Ride Through); Project 2021-04 (Modifications to PRC-002); and Project 2023-02 (Analysis and Mitigation of BES Inverter-Based Resource Performance Issues). Project 2023-02 was aligned with the associated regulatory directive from Order No. 901 and the other projects related to "Milestone 2" of the NERC work plan.

Proposed Reliability Standard PRC-030-1 would be a new Reliability Standard that would require the Generator Owner to identify, analyze, and mitigate IBR performance issues. Specifically, Reliability Standard PRC-030-1 would include four requirements for Generator Owners to: (1) document and implement a process for identifying full or partial loss of IBR Real Power output, along with exceptions that should not be identified; (2) analyze identified events

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10 *See* NERC Event Reports, https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx.

11 *See* May/June 2021 Odessa Disturbance, https://www.nerc.com/pa/rrm/ea/Pages/May-June-2021-Odessa-Disturbance.aspx.

and provide the analysis to a requesting Reliability Coordinator, Balancing Authority, or Transmission Operator; (3) create a Corrective Action Plan or technical justification when corrective actions are not implemented and provide it to the applicable Reliability Coordinator, Balancing Authority, or Transmission Operator; and (4) address performance risks through Corrective Action Plan implementation.

For these reasons, which are stated more fully below, NERC requests that the Commission approve the proposed Reliability Standard, 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:[12]

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III. REGULATORY BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[13] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the BPS, and with the duty of

[12] NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203, to allow the inclusion of more than two persons on the service list in this proceeding.
[13] 16 U.S.C. § 824o.

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.[14] Section 215(d)(5) of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard.[15] 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.[16]

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.[17]

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[18] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[19] In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable

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14 *Id.* § 824(b)(1).
15 *Id.* § 824o(d)(5).
16 18 C.F.R. § 39.5(a).
17 16 U.S.C. § 824o(d)(2); 18 C.F.R. § 39.5(c)(1).
18 Order No. 672 at P 334.
19 The NERC Rules of Procedure are available at https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC Standard Processes Manual is available at https://www.nerc.com/AboutNERC/RulesOfProcedure/Appendix_3A_SPM_Clean_Mar2019.pdf.

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.[20] 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 STANDARDS ADDRESSING INVERTER-BASED RESOURCES

A. History of Project 2023-02, Analysis and Mitigation of BES Inverter-Based Resource Performance Issues

Project 2023-02, Analysis and Mitigation of BES Inverter-Based Resource Performance Issues was initiated in response to multiple NERC disturbance reports,[21] including the Odessa disturbance report,[22] that identified the undesired performance of BPS-connected IBR during grid faults and detailed the systemic and significant BPS reliability risks that this undesired performance causes. The reports found that IBRs may trip for many different reasons, may cease current injection due to inverter controls, or may have unwanted plant-level controller interactions, resulting in unexpected and unwarranted loss of generation, which pose significant risks to BPS reliability.

Project 2023-02 was initiated to develop Reliability Standards that would provide analysis and mitigation of unexpected or unwarranted protection and control operations from IBRs. This includes any types of protections or controls that result in abnormal performance issues within the plant as well as any abnormal performance resulting in anomalous behavior of Real Power output

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20 ERO Certification Order at P 250.
21 *See* NERC Event Reports, https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx.
22 *See* May/June 2021 Odessa Disturbance, https://www.nerc.com/pa/rrm/ea/Pages/May-June-2021-Odessa-Disturbance.aspx.

from the facility during events. Specifically, Project 2023-02 was tasked with assuring adequate analyses of abnormal IBR performance, including a determination of the root cause, and determining whether any corrective measures should be required.

B. Order 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,[23] a final rule directing the development of Reliability Standards to address reliability issues associated with the growth of IBRs on the BPS. In the final rule, and in the preceding notice of proposed rulemaking ("NOPR"), the Commission cited 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."[24] The Commission concluded that, while NERC, the Commission, and industry groups all had efforts underway to address IBR risks, 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 Bulk-Power System.[25] The Commission directed NERC to develop new and revised Reliability Standards to address the following four topic areas related to IBRs: (1) data sharing;[26] (2) data and model validation;[27] (3) planning and operational studies;[28] and (4) performance requirements.[29]

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

24 *Id.* at P 25.

25 *Id.* at Section III.

26 *See id.* at PP 66-109 (discussing directives related to data sharing requirements).

27 *See id.* at PP 110-161 (discussing directives related to data and model validation requirements).

28 *See id.* at PP 162-177 (discussing directives related to planning and operational studies requirements).

29 *See id.* at PP 178-211 (discussing directives related to performance requirements).

Within these four topic areas, the Commission identified the specific reliability issues that NERC would need to address. In so doing, the Commission distinguished between IBRs currently registered with NERC for compliance purposes, or IBRs that will in the future be registered with NERC based on the approved revisions in the IBR Registration Approval Order ("registered IBRs");[30] 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 BPS reliability ("IBR-DERs").[31] 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."[32]

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

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[30] On November 17, 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 (citations omitted).

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].

[31] Order No. 901 at P 4 n.14.

[32] *Id.* at P 226.

explanation of how NERC would prioritize the development of new or modified Reliability Standards.[33] This work plan is described in the following section.[34]

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.[35] 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)
- **Milestone 4**: Development and Filing of Reliability Standards to Address Planning and Operational Studies Requirements for all IBRs (completion: November 4, 2026)

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33 *Id.* at PP 222-223.

34 *See* Standards Development Mapping of FERC Order 901 Directives and Other Guidance to Standards Development Projects, Draft SARs, and Pending SARs (May 2024), https://www.nerc.com/pa/Stand/Documents/Standards Development Mapping of FERC Order 901 Directives and Other Guidance to Standards Development Projects Draft SARs and Pending SARs.pdf.

35 *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].

Relevant to this filing, NERC identified the following standards projects to meet the goals set forth in Milestone 2 of the Order No. 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 would address IBR performance during disturbances commonly referred to as "ride-through." These standards would focus on how to adequately monitor, analyze, report, and mitigate IBR performance during the disturbance that occurs in "ride-through" periods.

As relevant to the instant petition and discussed in Section VI, proposed Reliability Standard PRC-030-1, would address, in part, the Order No. 901 directive to "require generator owners to communicate to the relevant planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities the actual post-disturbance ramp rates and the ramp rates to meet expected dispatch levels (i.e., generation-load balance)."[36] Specifically, proposed Reliability Standard PRC-030-1 would addresses the post-disturbance performance of IBR, not all IBR performance. Load balancing will be addressed under Milestone 4. 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,

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[36] Order No. 901 at P 208.

Inverter-Based Resource (IBR), for inclusion in the *Glossary of Terms used in NERC Reliability Standards*, 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[37] proposes to establish a new Reliability Standard PRC-028-1, Disturbance Monitoring and Reporting Requirements for IBR, to create new capability-based requirements for IBR. 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."[38] 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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[37] Project 2021-04 Modifications to PRC-002 - Phase II, https://www.nerc.com/pa/Stand/Pages/Project-2021-04-Modifications-to-PRC-002-2.aspx

[38] *See* proposed Reliability Standard PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources at A(3) (filed concurrently in a separate filing).

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 would be provided to a requesting Transmission Planner, Planning Coordinator, Transmission Operator, Balancing Authority, Reliability Coordinator, Regional Entity, or NERC as set forth in proposed Requirement R7. This data collected under PRC-028-1 would be used to inform the analysis conducted under PRC-030-1 Requirement R2, Part 2.1.2 that requires a Generator Owner to analyze its IBR facility performance during an identified full or partial loss of Real Power output, including documenting the facility's ride-through performance and Reactive Power response during the event. 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 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)

Addressed in a separate filing filed concurrently with this petition, Project 2020-02, Modifications to PRC-024,[39] 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. Proposed Reliability Standard PRC-029-1 would use a new defined term, Ride-through, that is proposed for inclusion in the *Glossary of Terms used in NERC Reliability Standards*. The proposed definition of Ride-through is as follows:

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

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

The proposed definition of Ride-through 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.

Proposed Reliability Standard PRC-029-1 would "ensure that IBRs Ride-through to support the Bulk Power System (BPS) during and after defined frequency and voltage excursions." [40] Proposed Reliability Standard PRC-029-1 would establish ride-through performance criteria and focus on the evaluation and documentation of ride-through capability. Proposed Reliability Standard PRC-029-1 is generally an event-based standard though it is also required to provide evidence of 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

As addressed in this filing, Project 2023-03, Analysis and Mitigation of BES Inverter-Based Resource Performance Issues,[41] proposes to establish new Reliability Standard PRC-030-1 to create new risk-based requirements for IBR Generator Owners related to IBR Performance. As discussed in detail herein, 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

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[40] *See* proposed Reliability Standard PRC-029-1 – Frequency and Voltage Ride-through Requirements for Inverter-based Resources at A(3) (filed concurrently in a separate filing).

[41] 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.

at least 20 MW and at least 10% of the plant's gross nameplate rating, occurring within a four second period.[42] 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 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 Bulk-Power System by addressing critical IBR reliability issues in accordance with Milestone 2 of NERC's Order No. 901 Work Plan.

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[42] 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.

VI. JUSTIFICATION FOR APPROVAL

Proposed Reliability Standard PRC-030-1 — Unexpected Inverter-Based Resource Event Mitigation is a new Reliability Standard that would include four requirements. Requirement R1 sets forth how events are to be identified, along with exceptions that should not be identified. Requirement R2 requires analysis of identified events, with specific elements assessed as described in subparts. It further requires that the analysis be communicated to a requesting Reliability Coordinator, Balancing Authority, or Transmission Operator. Requirement R3 requires a Corrective Action Plan or a technical justification when corrective actions are not implemented that must be provided to the applicable Reliability Coordinator, Balancing Authority, or Transmission Operator. Finally, Requirement R4 requires addressing the performance risk through Corrective Action Plan implementation.

As explained in Exhibit G, NERC developed the proposed Reliability Standard using NERC's standard development process. This process included multiple public comment and ballot periods. The NERC Board of Trustees adopted the proposed Reliability Standard 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-030-1, included as Exhibit E to this petition, as well as the Complete Record of Development, included as Exhibit G.

A. Title, Purpose, and Applicability

The title of proposed Reliability Standard PRC-030-1 is "Unexpected Inverter-Based Resource Event Mitigation." The purpose of proposed Reliability Standard PRC-030-1 is to "Identify, analyze, and mitigate unexpected Inverter-Based Resource (IBR) change of power output." As directed by FERC, proposed Reliability Standard PRC-030-1 would apply to

Generator Owners. Generator Owners are the functional entity responsible for identifying, analyzing, and mitigating unexpected IBR performance. The Generator Owner is accountable for changes and improvements to the IBR and facilities necessary to correct performance problems. This standard intentionally does not include requirements for the Balancing Authority, Reliability Coordinator, and Transmission Operator because other standards (e.g., EOP-004) place requirements on these entities for system level events.

The facilities covered by proposed Reliability Standard PRC-030-1 include (1) Bulk Electric System (BES) IBR; and (2) Non-BES IBR 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 BES 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.[43] As such, the applicability of proposed Reliability Standard PRC-030-1 is consistent with the applicability set forth in paragraph 208 of Order No. 901, in which the Commission directed NERC to "require generator owners to communicate to the relevant planning coordinators, transmission planners, reliability coordinators, transmission

[43] *See* IBR Registration Approval Order, *supra* note 30. 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.

operators, and balancing authorities the actual post-disturbance ramp rates and the ramp rates to meet expected dispatch levels (i.e., generation-load balance)."[44]

B. Requirement R1

Proposed Requirement R1 would implement a documented process to identify any complete facility loss of output or certain changes in Real Power output. It would contain thresholds for identifying events with sudden changes in Real Power and provide that changes in Real Power for certain reasons are excluded from the identification measures.[45] These steps are required to determine what events a Generator Owner must analyze under Requirement R2. Requirement R1 states:

> **R1.** Each applicable Generator Owner shall implement a documented process 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 4 second period. Changes in Real Power for the following are excluded: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
>
> - 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.

Under Requirement R1, a Generator Owner would implement a documented process to self-identify events that are sufficiently large to warrant an analysis of IBR performance for the identified event. Proposed Reliability Standard PRC-030-1 would utilize a minimum threshold of "at least 20 MW and at least 10% of the plant's gross nameplate rating." The purpose of the two

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[44] Order No. 901 at P 208. As discussed herein, the instant filing addresses post-disturbance ramp rates. Load balancing will be addressed through evaluation of performance in studies in Milestone 4 projects.

[45] Exhibit E, Technical Rationale at 1-2.

limits would be to make the trigger points manageable for both large and small facilities. This threshold would recognize that as the plant size grows, so does the trigger threshold.[46]

The drafting team considered that 20 MW is a common cutoff for other Reliability Standards, such as MOD-025, and that the NERC Rules of Procedure, entity registration section, references 20 MVA as a significant threshold.[47] Nameplate rating was used as the basis of the change (power or amperes) because it is the common reference in NERC and other industry standards and every generator has a nameplate rating that can be referenced. Moreover, nameplate rating is also included the BES definition.[48]"

The 10% nameplate rating for magnitude of Real Power change event threshold was selected to balance being large enough to screen out small Real Power changes but low enough to detect events that should be analyzed to ensure reliability. The percent change is intended to address facilities with greater than 200 MW nameplate rating where 10% is a significant change, otherwise the 20 MW threshold sets a minimum threshold for event identification. The 20 MW minimum change threshold causes the 10% change to only apply to 200 MW facilities and above.[49] For smaller capacity facilities, the use of only a percent change as the screening criteria would lead to identification of disturbances that are not likely to be significant for reliability.

While the Generator Owner should consider both Real Power and Reactive Power responses when an analysis is triggered, only Real Power is used as a threshold to trigger analysis. Real Power was selected as the monitored parameter to make implementation feasible across IBR

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46 *Id.* at 4.

47 *Id.* at 2-3 (referencing NERC Appendix 5B – Statement of Compliance Registry Criteria (Revision 8) (June 27, 2024) at p. 4 wherein Generator Owner includes under Define/Discussion "The entity that: 1) owns and maintains generating Facility(ies) (Category 1 GO); or 2) owns and maintains non-BES inverter based generating 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 (Category 2 GO)."

48 *Id.* at 3.

49 *Id.*

plant designs and back-end software system (e.g., SCADA). MW and Mvar are monitored on the SCADA software, while MVA is typically not present. MW was utilized instead of MVA due to Real Power loss being the primary concern in IBR events.[50]

Proposed Reliability Standard PRC-030-1 would require the Generator Owner 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. The intention of the four seconds was to limit the time within which the change in Real Power is calculated.[51]

In determining that the four second period was appropriate, the drafting team considered the various SCADA scan rates in use at Independent System Operators and Regional Transmission Organizations. SCADA monitoring is a likely method for monitoring Real Power changes. Real Power changes that occur and recover within one scan are not expected to be detected by the Requirement R1 process implemented by Generator Owners. The four seconds was not intended to define the scan period, but only to characterize the change as sudden when considering information on monitoring capabilities across the industry.[52]

The thresholds set forth in Requirement R1 are designed to rarely trigger events due to normal operation of an IBR facility if the facility is operating as expected.[53] The intention of the four second period was to specify what constitutes a sudden change in power, similar to the types of Real Power loss events described in NERC Disturbance Event reports. The four second threshold is meant to provide a significant exclusion because the change must occur quickly, within

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50 *Id.*
51 *Id.* at 5.
52 *Id.* at 4.
53 *Id.* at 7.

that time. Increasing the time would effectively reduce the rate of change and would identify more events than a four second window.[54]

The standard four second time only applies to the period of calculating the Real Power change, such as a sudden drop, for identifying valid events under Requirement R1. This time does not limit or imply any duration for the entire event. While the change must occur within the four second timeframe, the plant response may take tens of seconds or even minutes. The standard does specify or limit that time period.[55]

The term "changes in Real Power" encompasses both sudden decreases (i.e., loss of output) and increases (i.e., additional consumption) that may be caused by IBR misoperations that could affect system reliability. For instance, a battery energy storage system that mis-measures system frequency may unexpectedly enter a charging mode and suddenly increase Real Power draw.[56]

Proposed Requirement R1 would exclude the following from review:[57]

- 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.

These exclusions represent slow power changes that are expected with normal operations (e.g., variable output from weather, dispatch, planned outages, testing) or expected responses (e.g., loss of interconnection facilities).[58]

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54 *Id.*
55 *Id.*
56 *Id.* at 7-8.
57 *Id.* at 7.
58 *Id.*

C. Requirement R2

Proposed Requirement R2 would require a Generator Owner, within 90 calendar days of identifying a Real Power change under Requirement R1 or a request from the applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and change in IBR Real Power output, to analyze IBR facility performance during the event, and, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator. Specifically, proposed Requirement R2 states:

> **R2.** Each applicable Generator Owner, within 90 calendar days of a Real Power change event pursuant to Requirement R1 or following a request from its associated Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the Inverter-Based Resource(s) Real Power output, shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
>
> **2.1.** Analyze its Inverter-Based Resource facility performance during the event, including:
>
> **2.1.1.** Determine the root cause(s) of change(s) in Real Power output;
>
> **2.1.2.** Document the facility's Ride-through performance including Reactive Power response during the event;
>
> **2.1.3.** Assess any performance issues identified and if corrective actions are needed; and
>
> **2.1.4.** Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities.
>
> **2.2.** Upon request, provide the analysis results to the requesting associated Reliability Coordinator, Balancing Authority, or Transmission Operator.

Proposed Requirement R2 would require analysis of loss of Real Power output events that are self-identified by the Generator Owner utilizing the Requirement R1 thresholds. Proposed Requirement R2 would also provide an alternative path of event identification by the Balancing Authority, Reliability Coordinator, or Transmission Operator whereby they may request analysis of a grid disturbance they have identified. It is anticipated that some events would only be detected by one entity, thus, the combination of both identification methods would better identify events whereby poor IBR performance could potentially impact reliability.[59]

Requirement R2 would allow 90 calendar days to analyze expected versus actual IBR responses to place an emphasis on diligent resolution, while still allowing enough time to conduct an analysis and identify causes. Ninety days would allow adequate time for the Generator Owner to interact with manufacturers and examine the capabilities of equipment. In establishing this timeframe, the drafting team considered the PRC-004 timeline of 120 days, recognizing important differences between the application of these standards. The Reliability Standard PRC-004-4(i) Technical Rationale states: "[t]he 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed."[60] Identified events for analysis in PRC-030-1 are anticipated to include a fewer amount of IBR compared to similar requests under a broader scope of analysis required in PRC-004-4(i). The 90-calendar day period starts from the event date for Generator Owner-identified performance issue identified under Requirement R1, or upon the date of request from the Balancing Authority, Reliability Coordinator, or Transmission Operator regarding IBR responses identified during system events.[61]

Proposed Requirement R2 Part 2.1 would include subparts to analyze performance during a Real Power change event. Specifically, Requirement R2 Part 2.1.1 would require identification of the root cause of the event. Requirement R2 Part 2.1.2 would require that the facility's ride-through performance including Reactive Power response is documented. The analysis of ramp

59 *Id.* at 9.
60 *Id.* (citing Standard PRC-004-4(i) – Protection System Misoperation Identification and Correction Technical Rationale at pp. 37-38. Available at: https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-004-4(i).pdf).
61 *Id.* at 9.

rates would be included as a part of the ride-through performance analysis. Requirement R2 Part 2.1.3 would require that the Generator Owner assess the performance issue(s) and determine whether corrective actions are needed. Requirement R2 Part 2.1.4 would require that the Generator Owner consider the applicability of the root cause to its other IBR facilities. Collectively, the subparts would define the minimum features required as part of an effective analysis. Requirement R2 Part 2.2 would close the communication loop with the Balancing Authority, Reliability Coordinator, and Transmission Operator, when these entities request analysis results.[62]

D. Requirement R3

When performance issues and a need for corrective actions are identified by the Requirement R2 analysis, proposed Requirement R3 would require the Generator Owner to develop either a Corrective Action Plan, or a technical justification that addresses why corrective actions will not be implemented. The Generator Owner would be required to notify and provide the Corrective Action Plan, or the justification why no corrective actions are being implemented, to the associated Reliability Coordinator, Balancing Authority, and Transmission Operator within 60 calendar days of completing the analysis. If the analysis performed pursuant to Requirement R2 did not identify the need for corrective actions, then no action would be required under Requirement R3.[63] Specifically, Requirement R3 provides that:

> **R3.** If performance issues and a need for corrective actions were identified in Requirement R2 Part 2.1.3, each applicable Generator Owner shall, within 60 calendar days of completing the analysis in Requirement R2, develop one of the following and provide it to the associated Reliability Coordinator, Balancing Authority, and Transmission Operator: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
>
> - A Corrective Action Plan (CAP) for the identified Inverter-Based Resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R2 Part 2.1.3; or

62 *Id.*
63 *Id.* at 10.

- A technical justification that addresses why corrective actions will not be implemented.

Resolving the causes of IBR performance issues benefits BPS reliability by preventing recurrence. Corrective Action Plans are an established tool for resolving operational problems. The NERC *Glossary* defines a Corrective Action Plan as, "A list of actions and an associated timetable for implementation to remedy a specific problem."[64] Pursuant to Requirement R3 the Corrective Action Plan, or the technical rationale for not taking corrective action, would be communicated to the Reliability Coordinator, Balancing Authority, and Transmission Operator so that these entities 1) gain information potentially relevant to recent system events, and 2) may account for potential IBR performance issues in operational risk assessments.[65]

This proposed standard recognizes there may be multiple causes for IBR performance issues. In these circumstances, the Corrective Action Plan would include a remedy for the identified causes. The Corrective Action Plan may be revised if additional causes are found.[66] The 60-calendar day period for developing a Corrective Action Plan or technical justification is established based on industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.[67]

The development of a Corrective Action Plan is intended to document the specific corrective actions needed to be taken to prevent IBR performance issues from reoccurring, document the timetable for executing such actions, and conduct an evaluation of the Corrective Action Plan's applicability to the Generator Owner's other IBR, including those at other

64 *Id.*
65 *Id.*
66 *Id.*
67 *Id.*

locations.[68] The evaluation of these other IBR with similar designs would reduce the risk and the likelihood of similar IBR performance issues in other IBRs.[69]

Proposed Requirement R3 would address inadequate post-disturbance ramp rates as part of the corrective actions of the Corrective Action Plan. Under the Corrective Action Plan process, Generator Owners must provide the Corrective Action Plan or the technical rationale as to why no corrective actions have been implemented to the Reliability Coordinator, Balancing Authority, and Transmission Operator. The Corrective Action Plan process would communicate the IBR performance issues and the action being taken to address them with the intent of reducing the number of disturbance events occurring both at the generator level and the system level. Pursuant to the Corrective Action Plan, the Generator Owner will correct the facility reducing the amount of events that occur in the future.

Under proposed Requirement R3, the Generator Owner would be responsible for determining the extent of its evaluation concerning other IBRs and locations. The evaluation may result in the Generator Owner including actions to address IBR at other locations or to provide a technical justification that addresses why corrective actions will not be applied nor implemented.[70] Acceptable technical justification for not performing corrective actions would be expected to primarily have two characteristics: 1) interconnection requirements on IBR performance extending beyond those in place at the time of interconnection; and 2) it would require significant material modifications/qualified change.[71] Technical justifications for not performing corrective actions

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68 *Id.*
69 *Id.*
70 *Id.*
71 *Id.*

would not relieve the Generator Owner from compliance with other standards to the extent that other standards are applicable.[72]

For instances where the root cause is identified but the Generator Owner is not able to fully correct it, it is expected the Generator Owner will continue to work with the associated reliability entities and original equipment manufacturers to follow up on such instances and deploy corrective actions when they become available. The Generator Owner will continue to coordinate with associated reliability entities through improvements to root cause analysis and Corrective Action Plans until such a time the corrective actions are implemented. Such improvements include better data capture and fault logging capabilities for subsequent future events.[73]

E. Requirement R4

Proposed Requirement R4 would require the Generator Owner to implement the Corrective Action Plan, update the Corrective Action Plan if corrective actions or timetables change, and notify each associated Reliability Coordinator if corrective actions or timetables change as well as when the Corrective Action Plan is completed. Specifically, proposed Requirement R4 states that:

> **R4.** Each applicable Generator Owner shall, for each of its Corrective Action Plans developed pursuant to Requirement R3: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*
>
> **4.1.** Implement the CAP;
>
> **4.2.** Update the CAP if actions or timetables change; and
>
> **4.3.** Notify each associated Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

Proposed Requirement R4 would require that each applicable Generator Owner implement the Corrective Action Plan developed pursuant to Requirement R3 to mitigate deficiencies identified under Requirement R2. Under proposed Requirement R4, a Corrective Action Plan

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[72] *Id.*
[73] *Id.* at 9.

would be modified to account for adjustments to the corrective actions or scheduled timetable of activities. If the Corrective Action Plan is changed, the Generator Owner must notify each associated Reliability Coordinator. The entity must also notify the associated Reliability Coordinator when the Corrective Action Plan has been completed. The implementation of a properly developed Corrective Action Plan ensures that causes of unexpected changes in IBR power output are corrected in a timely manner.[74]

F. Consideration of Order No. 901 directive

Proposed Reliability Standard PRC-030-1 is responsive to the Commission's directive in Order No. 901 paragraph 208 to "require generator owners to communicate to the relevant planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities the actual post-disturbance ramp rates and the ramp rates to meet expected dispatch levels (i.e., generation-load balance)."[75] To address the reliability concerns underlying this directive, proposed Reliability Standard PRC-030-1 Requirement R1 addresses the post-disturbance performance of IBR, not all IBR performance. The load balancing component will be addressed through evaluation of performance in studies in Milestone 4 projects. To address the post-disturbance performance of IBR, proposed Reliability Standard PRC-030-1 would require Generator Owners to implement a documented process to identify any complete facility loss of output or certain changes in Real Power output. This includes establishing thresholds for identifying events with sudden changes in Real Power, it would also provide that changes in Real Power for certain reasons are excluded from the identification measures.[76] These steps are required to determine which events a Generator Owner must analyze under Requirement R2.

74 *Id.* at 11.
75 Order No. 901 at P 208.
76 Exhibit E, Technical Rationale at 1-2.

Proposed Requirement R2 would require Generator Owners, within 90 calendar days of identifying a Real Power change under Requirement R1 or a request from the applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and change in IBR Real Power output, to analyze IBR facility performance during the event, and provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator.

Proposed Requirement R2 Part 2.2 would require the Generator Owner to provide a requesting Reliability Coordinator, Balancing Authority, or Transmission Operator the results of the analysis conducted pursuant to Requirement Part 2.1.1 through 2.1.4 that includes: (1) determining the root cause(s) of change(s) in Real Power output; (2) documenting the facility's ride-through performance including Reactive Power response during the event; (3) assessing any performance issues identified and if corrective actions are needed; and (4) determining the applicability of the root cause(s) to the Generator Owner's other IBR facilities.

In consideration of the directive, the post-event documentation for the Generator Owner's facilities using ride-through performance, including the ramp rate and Reactive Power response during the event, would occur pursuant to Requirement R2 Part 2.1.2. Under Requirement R2 Part 2.1.2, a Generator Owner would be required to "[d]ocument the facility's Ride-through performance including Reactive Power response during the event." To accomplish this, the Generator Owner must evaluate Reactive Power performance, which includes an evaluation of ramp rates, and an evaluation of ride-through performance as defined in proposed Reliability Standard PRC-029-1. The evaluations would utilize the data collected under proposed Reliability Standard PRC-028-1 Requirement R4 Part 4.3 "[i]n addition, the data for Real Power and Reactive

Power flows expressed on a three-phase basis corresponding to each main power transformer(s) where current measurements are required."

In drafting proposed Reliability Standard PRC-030-1, the drafting team elected to provide the analysis results rather than raw data to a requesting Reliability Coordinator, Transmission Operator, or Balancing Authority. While raw data could be used to validate an analysis, it is the analysis, and not the raw data, that would inform the development of a Corrective Action Plan and thereby drive the improvements to reliability. Ultimately, it is the Generator Owner's responsibility to address performance issues with its IBR. Reliability Coordinators, Transmission Operators, or Balancing Authorities could review the raw data requested under proposed Reliability Standard PRC-028-1 Requirement R7 following a disturbance should they wish to independently verify the results of the Generator Owner's analysis of its IBR.

While the drafting team made the analysis results available to a requesting Reliability Coordinator, Transmission Operator, or Balancing Authority under Requirement R2 Part 2.2, they made disclosure of any Corrective Action Plan, or technical rationale for why no corrective action was implemented as a result of the analysis under Requirement R2, mandatory. Specifically, under Requirement R3, the Generator Owner would need to notify and provide the Corrective Action Plan, or the justification why no corrective actions are being implemented, to the associated Reliability Coordinator, Balancing Authority, and Transmission Operator. This would address any poor performance evaluated under PRC-030-1 Requirement R2, including inadequate post-disturbance ramp rates as part of the corrective actions of the Corrective Action Plan. The requirement requires communication of the IBR performance issues and the action being taken to address them with the intent of reducing the number of disturbance events occurring both at the generator level and the system level. Pursuant to the Corrective Action Plan the Generator Owner would address the root cause of the poor performance, thereby improving reliability during future grid disturbances.

For the reasons discussed above, proposed Reliability Standard PRC-030-1 addresses the Commission's directive in paragraph 208 of Order No. 901 by requiring that: (1) the analysis results be made available to the associated Reliability Coordinator, Balancing Authority, or Transmission Operator under proposed Reliability Standard PRC-030-1 Requirement R2; (2) any Corrective Action Plan, or technical rationale as to why no corrective action was implemented, under proposed Reliability Standard PRC-030-1 Requirement R3, be provided to the relevant Reliability Coordinator, Balancing Authority, or Transmission Operator; and (3) updates to the Corrective Action Plan be provided to the Reliability Coordinator under proposed Reliability Standard PRC-030-1 Requirement R4. Additionally, the dynamic disturbance recording data would be available to the Reliability Coordinator, Balancing Authority, or Transmission Operator under proposed Reliability Standard PRC-028-1 Requirement R7.

VII. ENFORCEABILITY OF PROPOSED RELIABILITY STANDARD

The proposed Reliability Standard includes 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.[77] Additionally, the proposed Reliability Standard includes VRFs and VSLs. The VRFs and VSLs provide guidance on the way that NERC will enforce the requirements of the proposed Reliability Standard. The VRFs and VSLs for the proposed Reliability Standard comport with NERC and Commission guidelines related to their

[77] Order No. 672 at P 327.

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.

VIII. EFFECTIVE DATE OF THE PROPOSED RELIABILITY STANDARD

NERC respectfully requests that the Commission approve the proposed Reliability Standard to become effective as set forth in the proposed Implementation Plan, provided in Exhibit B hereto. The proposed Implementation Plan includes as prerequisites proposed Reliability Standard PRC-029-1, and the definitions for "Ride-through" and "Inverter-Based Resource", which are being submitted in separate filings. The proposed Implementation Plan provides that the proposed Reliability Standard shall become effective on the later of 1) the first day of the first calendar quarter that is twelve (12) months after the effective date of the Commission'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 Commission's order approving Reliability Standard PRC-029-1. BES IBRs shall initially comply with all Requirements by the effective date of the standard.

The Implementation Plan provides a phased in compliance date for applicable Non-BES Inverter-Based Resources, to initially comply with Requirements R1, R2, R3, and R4 by the later of: (1) January 1, 2027; or (2) the effective date of the standard. Applicable Non-BES Inverter-Based Resources include 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. This phased in implementation complies with FERC'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."[78]

This Implementation Plan recognizes the urgent need for Reliability Standards to address IBR Corrective Action Plans to reduce disturbances, as demonstrated by multiple event reports of the last decade, while providing a reasonable period for entities to develop the necessary procedures and change their protection and control settings to meet the new requirements. This Implementation Plan also recognizes that a new class of Generator Owners will be registered soon, non-BES IBRs will be subject to compliance with NERC Reliability Standards for the first time, and there is a need to ensure fairness and consistency in the proposed standard's application among similar asset types. 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-030-1'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 BPS.

For the reasons stated above, the proposed implementation plan for proposed Reliability Standard PRC-030-1 balances the urgency in the need to implement the standard against the time needed to comply[79] and is just and reasonable, consistent with Commission guidance in Order No. 672, and responsive to the Commission's guidance for the implementation of IBR standards in

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[78] Order No. 901 at P 226.

[79] *See* Order No. 672 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.").

Order No. 901. NERC respectfully requests approval of the proposed implementation plan as submitted by NERC.

IX. CONCLUSION

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

- proposed Reliability Standard PRC-030-1, and associated elements included in Exhibit A, effective as proposed herein; and
- the proposed Implementation Plan included in Exhibit B.

Respectfully submitted,

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Date: November 4, 2024

Exhibit A

Proposed Reliability Standard PRC-030-1

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

PRC-030-1 is posted for a 5-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 25, 2023
SAR posted for comment	February 22, 2023 – March 23, 2023
25-day formal comment period with ballot	March 25, 2024 – April 18, 2024
34-day formal comment period with additional ballot	June 7, 2024 – July 10, 2024
22-day formal comment period with additional ballot	July 22, 2024 – August 12, 2024
17-day formal comment period with additional ballot	August 28 – September 13, 2024

Anticipated Actions	Date
5-day final ballot	September 23 –27, 2024
Board adoption	October 8-9, 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:** Unexpected Inverter-Based Resource Event Mitigation
2. **Number:** PRC-030-1
3. **Purpose:** Identify, analyze, and mitigate unexpected Inverter-Based Resource (IBR) change of power output.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Generator Owner
   - **4.2. Facilities:**
     - **4.2.1.** Bulk Electric System (BES) Inverter-Based Resources; and
     - **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.
5. **Effective Date:** See Implementation Plan for PRC-030-1

B. Requirements and Measures

R1. Each applicable Generator Owner shall implement a documented process 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 4 second period. Changes in Real Power for the following are excluded: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- 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.

M1. Each applicable Generator Owner shall have evidence which includes but is not limited to: (1) the documented process for detecting changes in output as described in Requirement R1, (2) evidence to demonstrate implementation of its documented process, (3) actual data recordings, and (4) identification of gross nameplate rating.

R2. Each applicable Generator Owner, within 90 calendar days of a Real Power change event pursuant to Requirement R1 or following a request from its associated Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the Inverter-Based Resource(s) Real Power output, shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. Analyze its Inverter-Based Resource facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in Real Power output;

2.1.2. Document the facility’s Ride-through performance including Reactive Power response during the event;

2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the applicability of the root cause(s) to the Generator Owner’s other Inverter-Based Resource facilities.

2.2. Upon request, provide the analysis results to the requesting associated Reliability Coordinator, Balancing Authority, or Transmission Operator.

M2. Each applicable Generator Owner shall have dated documentation of the required analysis developed in accordance with Requirement R2. Evidence may include, but is not limited to: (1) an analysis report, (2) actual data recordings or derivations, (3) documents describing the device specification and device configuration or settings, and (4) plant configuration.

R3. If performance issues and a need for corrective actions were identified in Requirement R2 Part 2.1.3, each applicable Generator Owner shall, within 60 calendar days of completing the analysis in Requirement R2, develop one of the following and provide it to the associated Reliability Coordinator, Balancing Authority, and Transmission Operator: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- A Corrective Action Plan (CAP) for the identified Inverter-Based Resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R2 Part 2.1.3; or
- A technical justification that addresses why corrective actions will not be implemented.

M3. Each applicable Generator Owner shall have dated evidence (electronic or hardcopy format) that demonstrates it developed a CAP or a technical justification, and evidence of transmittal to the Reliability Coordinator, Balancing Authority, and Transmission Operator in accordance with Requirement R3.

R4. Each applicable Generator Owner shall, for each of its Corrective Action Plans developed pursuant to Requirement R3: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

4.1. Implement the CAP;

4.2. Update the CAP if actions or timetables change; and

4.3. Notify each associated Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

M4. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, communication with equipment manufacturers, and communication with each associated Reliability Coordinator that documents the implementation, updating, or completion of a CAP in accordance with Requirement R3.

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 shall keep data or evidence of Requirement R1, and R2, Measure M1, and M2 for 36 calendar months following the completion of each Requirement.
   - The Generator Owner shall retain evidence of Requirement R3, Measure M3, including any supporting analysis per Requirements R2 and R3, for a minimum of 36 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.
   - The Generator Owner shall retain evidence of Requirement R4, Measure M4 for a minimum of 36 calendar months following completion of each CAP.

   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 responsible entity failed to implement a documented process to identify changes in Real Power output in accordance with Requirement R1.
R2.	The responsible entity performed an analysis in accordance with Requirement R2, but in more than 90 calendar days but less than 120 calendar days of an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 120 or more calendar days but less than 150 calendar days of an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 150 or more calendar days but less than 180 calendar days of an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 or Part 2.1.4. OR The responsible entity failed to provide the analysis results from the requesting entity in accordance with Requirement R2, Part 2.2.	The responsible entity developed an analysis in accordance with Requirement R2, but in 180 calendar days or more of an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 and Part 2.1.4. OR The responsible entity failed to document the facility's Ride-through performance in accordance with Requirement R2, Part 2.1.2 OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The responsible entity failed to determine the applicability of other Inverter-Based Resource facilities in accordance with Requirement R2, Part 2.1.4.
R3.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 60 calendar days, but provided it within 90 calendar days.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 90 calendar days, but provided it within 120 calendar days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 120 calendar days, but provided it within 150 calendar days OR The developed CAP did not include corrective actions for other facilities owned by the Generator Owners as identified in Requirement R2 Part 2.1.3, if necessary. OR The developed CAP or technical justification was not provided to the associated Reliability Coordinator, Balancing Authority, and Transmission Operator.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented, within 150 calendar days.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R4.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan.

Version History

Version	Date	Action	Change Tracking
Initial Draft	**02/06/2024**	**Draft**	
Second Draft	**06/07/2024**	**Draft**	
Third Draft	**07/22/2024**	**Draft**	
Fourth Draft	**08/28/2024**	**Draft**	

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit B

Implementation Plan

Implementation Plan

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1

Applicable Standard(s)

- PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation

Requested Retirement(s)

- None

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Resources
- Ride-through
- Inverter-Based Resource (IBR)

Applicable Entities

- Generator Owner (GO)

Background

Multiple NERC disturbance reports,[1] including the Odessa disturbance report,[2] identified the undesired performance of Bulk Power System (BPS)-connected Inverter-Based Resources (IBR) during grid faults and have elaborated on the systemic and significant BPS reliability risks that this undesired performance can pose. IBRs may trip for many different reasons, may cease current injection due to inverter controls, or may have unwanted plant-level controller interactions. These types of issues have been extensively documented in the NERC reports. The resulting unexpected and unwarranted loss of generation poses a significant risk to BPS reliability. Project 2023-02 was initiated to address the reliability-related need and benefit by requiring analysis and mitigation of unexpected or unwarranted protection and control operations from Inverter-Based Resources (IBR) following the identification of such a performance issue.

1 https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx
2 https://www.nerc.com/pa/rrm/ea/Pages/May-June-2021-Odessa-Disturbance.aspx

In October 2023, FERC issued Order No. 901,[3] which directs the development of new or modified reliability standards, including 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[4]. Within the work plan, NERC identified three active Standards Development Projects that would need to be filed for regulatory approval with FERC November 4, 2024. These projects include 2020-02 Modifications to PRC-024 (Generation Ride Through),[5] 2021-04 Modifications to PRC-002-2,[6] and 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues.[7]

Project 2023-02

Proposed Reliability Standard PRC-030-1 is a new Reliability Standard that requires the Generator Owner to identify, analyze, and mitigate IBR performance issues. The scope of this project was adjusted to align with associated regulatory directives from FERC Order No. 901 and the scope of other projects related to "Milestone 2" of the NERC work plan. Specifically, Reliability Standard PRC-030-1 includes four (4) Requirements that require Generator Owners to: (1) define how events are to be identified, along with exceptions that should not be identified; (2) analyze identified events; (3) create a Corrective Action Plan (CAP) or technical justification when corrective actions are needed; and (4) mitigate performance risk through CAP implementation.

Proposed Reliability Standard PRC-030-1 includes the analytics and CAPs that complement Project 2020-02, which proposes new Reliability Standard PRC-029-1 addressing Ride-through and performance requirements for IBRs. The corresponding new data recording requirements are covered in Project 2021-04 and the new PRC-028-1 Reliability Standard.

General Considerations

This implementation plan recognizes the urgent need for Reliability Standards to address IBR CAPs to reduce disturbances, as demonstrated by multiple event reports of the last decade, while providing a reasonable period for entities to develop the necessary procedures and change their protection and control settings to meet the new requirements. The Electric Reliability Organization (ERO) Enterprise acknowledges that while there are IBR currently in operation, a standard is not in place that addresses CAPs for IBR.

[3] *Reliability Standards to Address Inverter-Based Resources,* Order No.901, 185 FERC ¶ 61,042 (2023); https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false

[4] *See Informational Filing of the N. Am. Elec. Reliability Corp. Regarding the Development of Reliability Standards Responsive to Order No. 901.*, Docket No. RM22-12-000 (January 18, 2024).

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

[6] *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

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

The ERO Enterprise acknowledges that Generator Owners and Generator Operators owning or operating BPS 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-030-1'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 BPS.

This implementation plan requires that all BES IBRs fully comply with the requirements by the effective date. It requires that applicable non-BES IBRs[8] comply by the later of: (1) January 1, 2027; or (2) the effective date of the standard.

Effective Date

The effective date for the proposed Reliability Standard is provided below.

Standard PRC-030-1

Where approval by an applicable governmental authority is required, Reliability Standard PRC-030-1 shall become effective on the 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, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard PRC-030-1 shall become effective on the later of 1) the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees; or 2) the first day of the first calendar quarter that is twelve (12) months after the date Reliability Standard PRC-029-1 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

[8] The facilities section of the standard applies to "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."

PRC-030-1 Phased-in Compliance Dates

Requirements R1, R2, R3, and R4

Bulk Electric System IBRs
Bulk Electric System IBRs shall initially comply with all Requirements by the effective date of the standard.

Applicable Non-BES IBRs
Applicable Non-BES Inverter-Based Resources shall initially comply with Requirements R1, R2, R3, and R4 by the later of: (1) January 1, 2027; or (2) the effective date of the standard. Applicable Non-BES Inverter-Based Resources include 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.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit C

Order No. 672 Criteria

EXHBIIT 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]

Proposed Reliability Standard PRC-030-1 – Unexpected Inverter-Based Resource Event Mitigation would advance the reliability of the Bulk-Power System ("BPS") by requiring Generator Owners to identify, analyze, and mitigate Inverter-Based Resources ("IBR") performance issues. Specifically, Reliability Standard PRC-030-1 would include four requirements for Generator Owners to: (1) document and implement a process for identifying full or partial loss of IBR Real Power output, along with exceptions that should not be identified; (2) analyze identified events and provide the analysis to a requesting Reliability Coordinator,

[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.").

Balancing Authority, or Transmission Operator; (3) create a Corrective Action Plan or technical justification when corrective actions are not taken and provide it to the applicable Reliability Coordinator, Balancing Authority, or Transmission Operator; and (4) address performance risks through Corrective Action Plan implementation.

The proposed Reliability Standard is focused on addressing the post-disturbance performance of IBR, not all IBR performance, and would address the urgent need for Corrective Action Plans to reduce poor IBR ride-through performance from exacerbating system disturbances, as demonstrated by multiple event reports of the last decade. The proposed Reliability Standard is thus designed to achieve a specific reliability goal and contains a technically sound means to achieve that goal.

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 Standard is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. Proposed Reliability Standard PRC-030-1 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. The proposed Reliability Standard clearly articulates the actions that applicable entities must take to comply with the standards.

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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.").

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 violations. For these reasons, the proposed Reliability Standard includes 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 Standard contains 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.

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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.").

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.").

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 Standard achieves its reliability goals effectively and efficiently in accordance with Order No. 672. Proposed Reliability Standard PRC-030-1 would provide robust and technically justified requirements for Generator Owners to identify, analyze, and mitigate IBR performance issues. Proposed Reliability Standard PRC-030-1 is focused on addressing the post-disturbance performance of IBR. In drafting proposed Reliability Standard PRC-030-1, the drafting team struck an appropriate balance between the reliability need for high quality analysis of certain Real Power events and the urgent need for Corrective Action Plans to reduce poor IBR ride-through performance from exacerbating system disturbances while minimizing undue burdens on Generator Owners responsible for conducting such analysis.

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]

[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.").

[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 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.").

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-030-1 reflects a measured and reasoned consideration of the need for Generator Owners to identify, analyze, and mitigate IBR performance issues, balanced against the implementation burden on entities. Proposed Reliability Standard PRC-030-1 would address the urgent need for Corrective Action Plans to reduce poor IBR ride-through performance from exacerbating system disturbances.

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 Standard 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-030-1 would apply to all IBRs due to the need to identify, analyze, and mitigate post-disturbance performance issues.

[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 Standard 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 PRC-030-1 – Unexpected Inverter-Based Resource Event Mitigation is well documented in multiple disturbance reports and highlighted in Order No. 901.

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

The implementation plan for the proposed Reliability Standard is just and reasonable and appropriately balances the urgency in the need to implement the standard 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 Standard would become effective on 1) the first day of the first calendar quarter that is twelve (12) months after the effective date of the Commission'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 Commission's order approving Reliability Standard PRC-029-1. BES IBRs shall initially comply with all Requirements by the effective date of the standard. The implementation of proposed Reliability Standard PRC-030-1 would then follow a phased-in compliance approach that would

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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.").

require applicable Non-BES Inverter-Based Resources to initially comply with Requirements R1, R2, R3, and R4 by the later of: (1) January 1, 2027; or (2) the effective date of the standard. Applicable Non-BES Inverter-Based Resources include 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. This phased in implementation complies with FERC'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."[11]

The proposed implementation plan recognizes the urgent need for Reliability Standards to address IBR Corrective Action Plans to reduce disturbances, as demonstrated by multiple event reports of the last decade, while providing a reasonable period for entities to develop the necessary procedures and change their protection and control settings to meet the new requirements.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[12]

The proposed Reliability Standard was developed in accordance with NERC's Commission-approved processes for developing and approving Reliability Standards. **Exhibit G**

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11 Order No. 901 at P 226.

12 *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.").

includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the proposed Reliability Standard. 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.[13]

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

12. Proposed Reliability Standards must consider any other appropriate factors.[14]

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

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13 *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.").

14 *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.").

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Exhibit D

Consideration of Order No. 901 Directives

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Mapping Document
Consideration of FERC Order 901 Directives

Project 2023-02 Unexpected Inverter-Based Resource Event Mitigation
August 2024

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, there 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.

FERC Order 901 Directives	
Directive Language	**Consideration of Directives**
P58. 208 "Further, the Reliability Standards must require generator owners to communicate to the relevant planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities the actual post-disturbance ramp rates and the ramp rates to meet expected dispatch levels (i.e., generation-load balance)."	The Drafting Team addressed this directive in proposed PRC-030-1 through Requirements R1, R2, R3, and R4. Requirement R1 requires GOs to implement a documented process to identify any complete facility loss of output or certain changes in Real Power output. Requirement R1 also includes exclusions to these identification measures.

[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

	Requirement R2 requires that GOs, within 90 calendars of identifying a Real Power change under Requirement R1 or a request from the applicable RC, BA, or TOP that identified a Disturbance and change in IBR Real Power output, to analyze IBR facility performance during the event, and, provide the analysis results to the requesting applicable RC, BA, or TOP. Post event documentation for the GO's facilities using Ride-Through performance, including the ramp rate and reactive power response during the event, occurs in Requirement R2 Parts 2.1.1 and 2.1.3. Requirements R2 also gives the ability for communication from RC, BA, TOP to the GO requesting analysis results. Requirements R3 and R4 require the GO to develop a Corrective Action Plan (CAP), implement the CAP, and update the CAP if actions or timetables change. The GO will need to notify and provide the CAP, or the justification why no corrective actions are needed, to the applicable entity.

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Exhibit E

Technical Rationale

Technical Rationale

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1 | September 2024

PRC-030-1 – Unexpected Inverter-Based Resource Event Mitigation

Rationale for Applicability Section
The functional entity responsible for identifying, analyzing, and mitigating unexpected Inverter Based Resources (IBR) performance is the Generator Owner (GO). The Generator Operator (GOP) is not included because of the accountability and coordination issues introduced by listing both GO and GOP as responsible functional entities. The GO is accountable for changes and improvements to the IBR and facilities necessary to mitigate performance problems. Further, this standard intentionally did not include requirements for the Balancing Authority (BA), Reliability Coordinator (RC), and Transmission Operator (TOP) because other standards (e.g., EOP-004) place requirements on these entities for system level events.

General rationale
Aligned with the Project 2023-02 Standards Authorization Request (SAR), the Requirements are structured to identify, analyze, and mitigate IBR performance issues. The SAR discusses how a series of NERC disturbance reports have "identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that these pose". [1,] In particular, IBR performance during events has included tripping or momentary cessation that is unexpected, unwarranted, and poses reliability challenges.

Requirement R1 defines how events are to be identified, along with exceptions that should not be identified. Requirement R2 requires analysis of identified events, with specific elements assessed as described in subparts. Requirement R3 requires a Corrective Action Plan (CAP) or technical justification when corrective actions are needed. Finally, R4 requires mitigation of the performance risk through CAP implementation. The flow of these requirements is summarized in Figure 1.1.

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[1] *Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Standard Authorization Request, at p. 1 (accepted August 23, 2023) (referencing* Event Reports (nerc.com)*)*

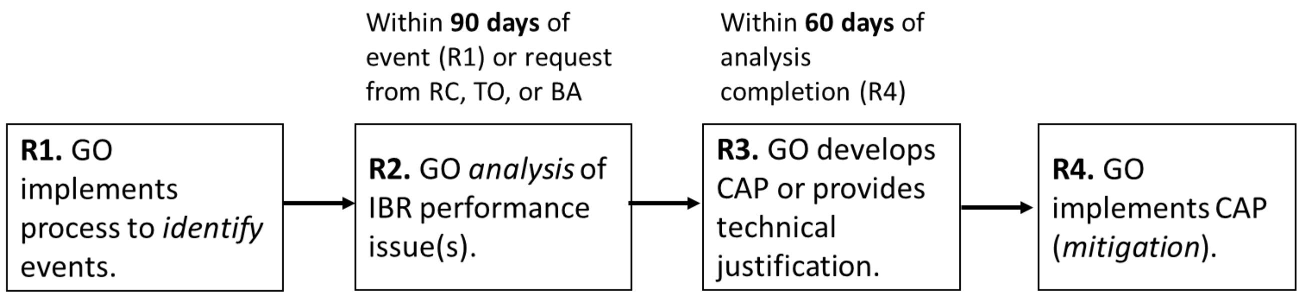


Figure 1.1: Relationship of Requirements in PRC-030-1

The Requirement R1 contains thresholds for identifying events with sudden changes in Real Power. Figure 1.2 depicts the threshold criteria and logic used in Requirement R1, along with additional details of process flow in Requirement R2.

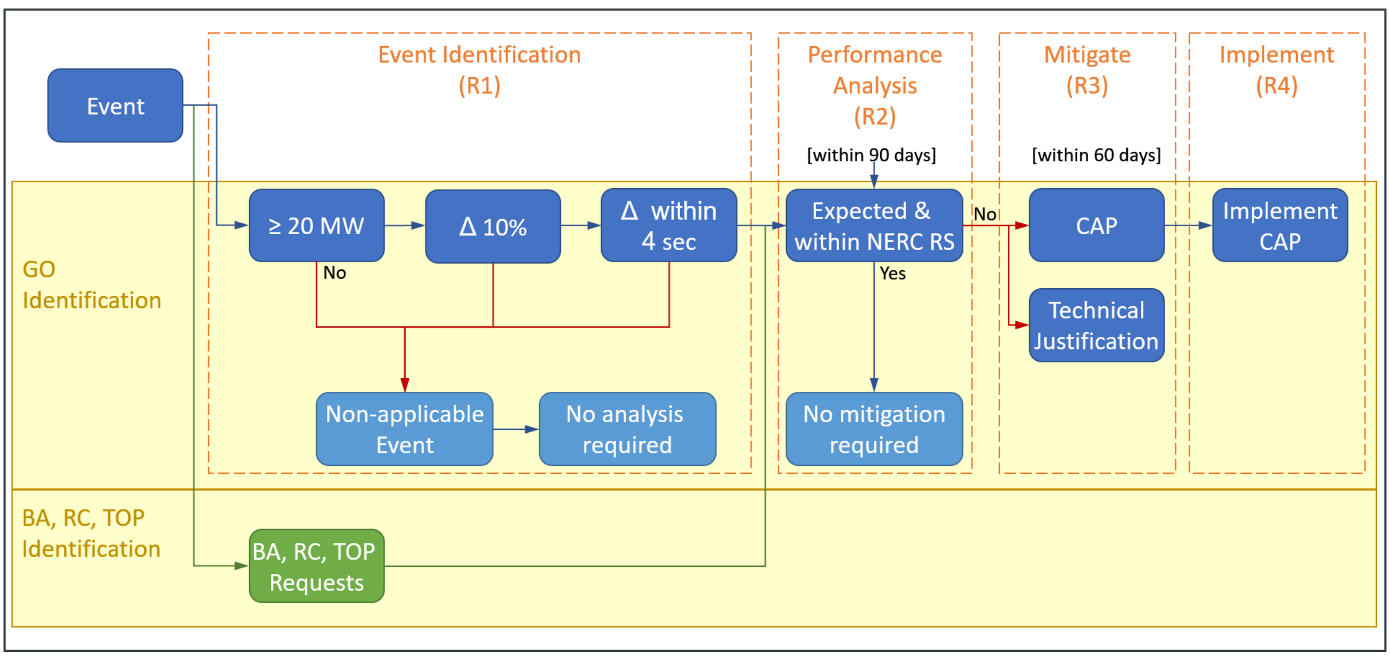


Figure 1.2: PRC-030-1 Flowchart

Rationale for Requirement R1

The intent of Requirement R1 is for the Generator Owner (GO) to implement a documented process to self-identify events that are sufficiently large to warrant an analysis of IBR performance for the identified event. For that reason, the Drafting Team included the 20 MW minimum threshold, which is a common

cutoff for other Reliability Standards, such as MOD-025, to reduce the number of potential events. NERC Category two in the ROP, entity registration section references 20 MVA as a significant threshold.

While the GO should consider both active and reactive power responses when an analysis is required, only Real Power is used as a threshold to trigger analysis. Real Power was selected as the monitored parameter to make implementation feasible across IBR plant designs and back end software system (e.g., SCADA). MW and Mvar are monitored on the SCADA software, while MVA is typically not present. The Drafting Team (DT) went with MW instead of MVA due to Real power loss being the primary concern in IBR events.

The thresholds for event identification in Requirement R1 provide a two-tier approach depending on the size of the IBR facility. The table below shows the two tiers and the thresholds that should be used to identify events. In addition, all unexpected events in which there is a complete loss of MW output, or active drops to 0 MW, should be identified regardless of plant size and output. This of course excludes planned ramp downs, and all other exclusions listed in Requirement R1 (solar end of day ramp down, planned outages, loss of connecting transmission facilities, Misoperations identified in PRC-004, etc.).

Facility Nameplate Rating	Threshold
200 MW or less	20 MW
Greater than 200 MW	10% of Nameplate Rating (e.g. 30 MW for 300 MW Facility)

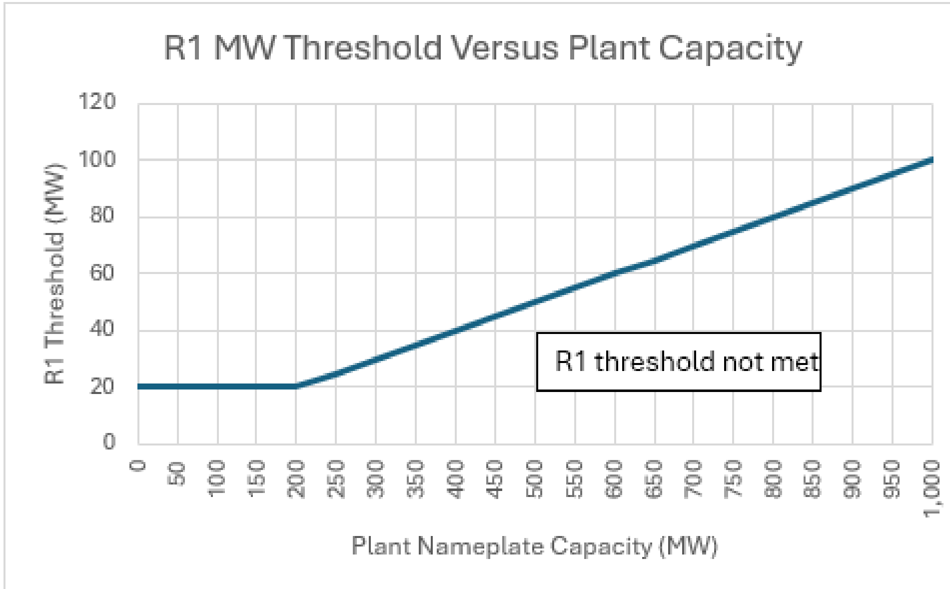
Nameplate rating was used as the basis of the change (power or amperes) because it is the common reference in NERC and other industry standards. Nameplate was chosen because every generator has a nameplate rating that can be referenced. Nameplate rating is also included as the reference point as it is included in the BES definition.

The 10% of nameplate rating for magnitude of Real Power change event threshold was chosen to be large enough to screen out small Real Power changes but low enough to detect events that should be analyzed for reliability purposes. The percent change is intended to address facilities with greater than 200 MW nameplate rating where 10% is a significant change, otherwise the 20 MW threshold sets a minimum threshold for event identification. The 20 MW minimum change threshold causes the 10% change to only apply to 200 MW facilities and above.
For smaller capacity facilities, the use of only a percent change as the screening criteria would lead to identification of disturbances that are not likely to be significant for analysis.

To restate the criteria another way:

- For plants with 0 – 200 MW gross nameplate rating, the change must be at least 20 MW,
- For plants with 200 MW gross nameplate rating and larger, the change must be at least 10% of the gross nameplate rating.

The criteria could be charted as depicted below.



Requirement R1 Threshold met

The purpose of the two limits is to make the trigger points manageable for both large and small facilities. The Drafting Team (DT) recognizes that as the plant size grows, so does the trigger threshold, which is why the threshold was set at 10% rather than something larger, like 20%. While the GO would not be required to identify events below the 10% threshold for large plants, the Reliability Coordinator (RC) is explicitly given the option to request a review in the requirement.

The DT revised the wording of Requirement R1 to clarify that the DT's intent is at least 20 MW for facilities with a nameplate rating of 200 MW or less and at least 10% change for facilities with a nameplate rating over 200 MW. While the DT considered the existing criteria sufficient, a complete loss of the facility was also included as a Requirement R1 condition.

At one point, the DT considered using the terms "sudden" and "unexpected", but that created uncertainty and concerns about consistent application. Therefore, the DT chose to bound the initial change at event onset to a four second timeframe.

The various SCADA scan rates in use at ISOs/RTOs as well as NERC standard minimum required scan rates were considered in selecting four seconds. SCADA monitoring is a likely method for monitoring Real Power changes. Power changes that occur and recover within one scan are not expected to be detected by the Requirement R1 process implemented by GOs. The four seconds was not intended to define the scan period, but only to characterize the change as sudden when considering information on monitoring capabilities across the industry. If a facility is using a scan rate of four seconds or greater to monitor Real Power output, the GO should use the change in Real Power output in one scan rate to identify events meeting Requirement R1 criteria. It should be noted that using longer time periods or scan rate could lead

to a need for more sophisticated event screening or may otherwise lead to identification of more invalid events that occur on slower timescales.

The intention of the four seconds was to limit the time within which the change in Real Power is calculated. The DT also considered that IBR generation plants following normal operation dispatch commands tend to move more slowly. For example, using the 20 MW for four seconds, the change rate is 5MW/sec, or 300 MW/min. Lower ramp rates would not be expected to meet the Requirement R1 criteria.

The following set of charts, in Figure 1.4, are examples of expected event scenarios and whether they meet the Requirement R1 criteria.

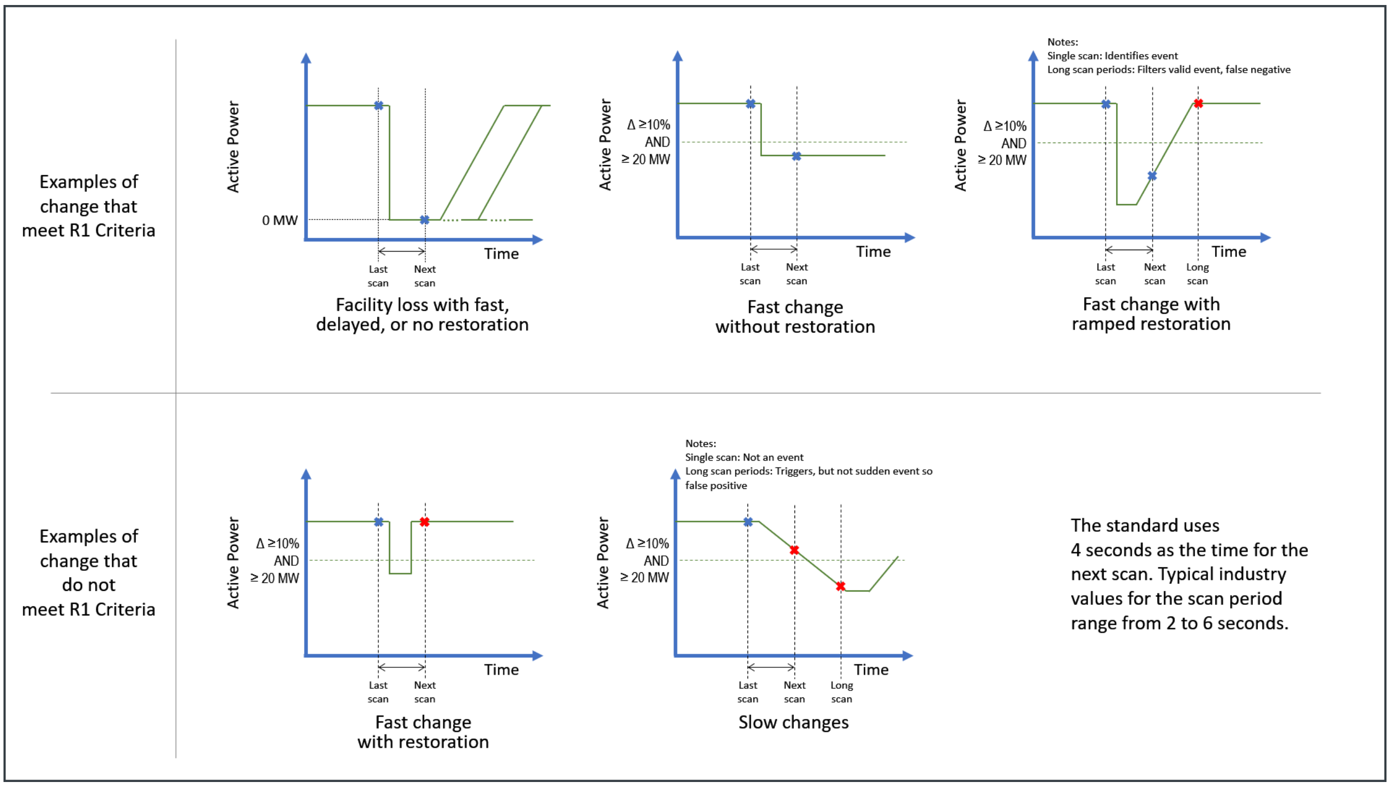


Figure 1.4: PRC-030-1 Flowchart

Due to concern voiced by industry that the thresholds defined in Requirement R1 could be often exceeded during the normal operation of an IBR facility, the DT examined three IBR facilities in Texas to determine the frequency of such events.

Solar facility in West Texas with 160 MW nameplate rating:
The DT analyzed one year of data encompassing all of 2023 and found five instances in which the facility changed 20 MW or more within a four second period. All five instances were related to ride-through performance issues previously identified by the Reliability Coordinator. There were zero events in which

Real Power changed 20 MW or more within a four second period due to change of irradiance, ramping due to dispatch, or other reasons listed as exclusions to Requirement R1.

Wind facility in Texas Panhandle with 300 MW nameplate rating:
The DT analyzed one year of data encompassing all of 2023 and found zero real events in which the facility changed 30 MW or more within a four second period. There were several events that were triggered due to dropouts of telemetry from the facility, but telemetry from the Point of Interconnection verified that there were no actual drops in Real Power from the facility at the time.

Solar Facility in Central Texas with 500 MW nameplate rating:
The DT analyzed one month of data for June 2024 and found seven events in which the facility changed 50 MW or more within a four second period, the first four of these events appear to be caused by curtailment issues. The plant was either being curtailed or was released from curtailment at the time which four of the seven events were detected. One of those events showed a large increase of irradiance at the time, but it is unclear if the change of irradiance alone caused the sudden increase in generation or if it was due to improper curtailment ramp rates, or a combination of the two. Two of the other events were related to large oscillations lasting up to an hour in which peak to peak magnitude of the oscillation exceeded 50 MW. The last event was due to a Power Plant Controller issue that caused a sudden drop in Real Power of 246 MW and was previously identified by the Reliability Coordinator. Under Requirement R1 requirements, three of the seven events would meet criteria and need to be analyzed in Requirement R2. The table below summarizes the results:

Date/Time	Four second MW change	Increase/ Decrease	Significant Irradiance Change	Cause	Should be Analyzed in R2
6/4/2024 1:25:00 PM	83	Increase	Yes	Curtailment issue/ Irradiance change?	No (Resource dispatch and/or change in irradiance exclusion)
6/4/2024 5:00:00 PM	192	Increase	No	Curtailment released	No (Resource dispatch exclusion)
6/14/2024 8:02:00 AM	57	Increase	No	Curtailment issue	No (Resource dispatch exclusion)
6/14/2024 11:36:00 AM	138	Increase	No	Curtailment issue	No (Resource dispatch exclusion)
6/17/2024 11:45:00 AM	246	Decrease	No	Plant controller issue	Yes
6/23/2024 12:30:00 PM	50	Both	No	Oscillation Event	Yes (peak to peak magnitude >50 MW observed)
6/26/2024 4:00:00 PM	78	Both	No	Oscillation Event	Yes (peak to peak magnitude >50 MW observed)

The DT also analyzed data covering one month from four facilities in Hawaii and found only one event that exceeded thresholds in Requirement R1. Since facilities in this area are generally smaller, all four facilities

analyzed were less than 200 MW in nameplate rating, so a 20 MW threshold was used for analysis. The DT also looked at an extended time period of 60 seconds, and as expected, more events were identified with the extended time period.

Plant #	1	2	3	4
Technology	Wind	PV	PV/BESS (AC Couple)	BESS Standalone
Facility Nameplate Rating (MW)	69	46	39	135
# of event (4 second, >20 MW)	0	0	0	1 (cause unknown)
# of event (60 second, >20 MW)	0	0	0	8

Due to the above analysis, the DT believes the thresholds in Requirement R1 would rarely trigger events due to normal operation of an IBR facility if the facility is operating as expected. The DT only found one possible instance of a facility exceeding the thresholds due to change of irradiance and wind speed, and it was likely caused by improper curtailment ramp rates programmed into the Power Plant Controller. In addition, the DT reviewed papers published by NREL on Solar PV Variability at Small Timescales and Variability of Wind Power Output, which concludes that change in irradiance and wind speed would not have large impacts to changes in output within a narrow timeframe such as a four second period.

The intention of the four second period was to specify what constitutes a sudden change in power, similar to the types of Real Power loss events described in NERC Disturbance Event reports. The DT considered using the term “scan period” to define the change period, because this scan period is the basis of the time, but chose to stay with the four second time specification. Four seconds is a common industry practice, MISO’s scan rate, which is one of the longest, has a time duration of four seconds. The four second threshold is meant to provide a significant exclusion because the change must occur quickly, within that time. Increasing the time effectively reduces the rate of change and would identify more events than a four second window. The intent is to exclude from review slow power changes expected with normal operations (e.g., variable output from weather, dispatch, planned outages, testing) or expected responses (e.g., loss of interconnection facilities), which were defined as bullet points to Requirement R1.

The standard four second time only applies to the period of calculating the Real Power change, such as a sudden drop, to be considered valid events identified under Requirement R1. This time does not limit or imply any duration for the entire event. While the change must occur within the four second timeframe, the plant response may take tens of seconds or even minutes. The standard does specify or limit that time period.

The term “changes in Real Power” encompasses both sudden decreases (i.e., loss of output) and increases (i.e., additional consumption) that may be caused by IBR mis-operations that could affect system

reliability. For instance, a battery energy storage system that mis-measures system frequency may unexpectedly enter a charging mode and suddenly increase Real Power draw.

Photovoltaic (PV) example 1 – qualifying:
PV facility with gross nameplate rating of 220 MW is operating with active output of 80 MW. During a transmission system fault event,[2] the plant exhibits a near instantaneous Real Power output drop to 50 MW.

The change in apparent power in under four seconds is 30 MW, which exceeds 22 MW, the greater of 10% of the plant's gross nameplate (22 MW) or 20 MW. This IBR performance event is required to be captured by the GO's process implemented in Requirement R1.

PV example 2 – non-qualifying:
PV facility with gross nameplate rating of 80 MW is operating with active output of 60 MW. During a transmission line fault event,[1] the plant exhibits a near instantaneous Real Power output drop to 42 MW.

The change in apparent power in under four seconds is 18 MW, <u>not</u> exceeding 20 MW, the greater of 10% of the plant's gross nameplate rating (8 MW) or 20 MW. This IBR performance event is <u>not</u> required to be captured by the GO's Requirement R1 process.

Battery Energy Storage System (BESS) example 1 – qualifying:
BESS facility with gross nameplate power output rating of 80 MW is operating as a load drawing 50 MW. During a power plant controller (PPC) malfunction event of the BESS facility, the PPC incorrectly estimates system frequency sending an incorrect frequency response signal causing the plant to exhibit a near instantaneous change in real power to 10 MW injection.

The change in apparent power in under four seconds is 60 MW, which exceeds 20 MW, the greater of 10% of the BESS gross nameplate (8 MW) or 20 MW.
This IBR performance event is required to be captured by the GO's Requirement R1 process.

BESS example 2 – non-qualifying:
BESS facility with gross nameplate power output rating of 80 MW is outputting 40 MW. The BESS facility is curtailed by the Reliability Coordinator such that the plant exhibits a near instantaneous Real Power decrease to 15 MW.

The change in apparent power in under four seconds is 25 MW, exceeding 20 MW, the greater of 10% of the plant's gross nameplate rating (8 MW) or 20 MW. However, the change in apparent power is the result of the Reliability Coordinator curtailment which is an exempt event per Requirement R1. This IBR performance event is <u>not</u> required to be captured by the GO's Requirement R1 process.

[2] The transmission line fault is assumed not to be on the line connecting the IBR to the system, but rather is a fault remote from the IBR.

Rationale for Requirement R2

Requirement R2 requires analysis of events that meet Requirement R1 thresholds. Requirement R2 also provides an alternative path of event identification by the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operators (TOP). It is anticipated that some events would only be detected by one entity, but the combination of both identification methods would better identify events potentially posing reliability challenges.

Requirement R2 allows 90 days to analyze expected versus actual IBR responses to place an emphasis on diligent resolution, while still allowing enough time to conduct an analysis and identify causes. Ninety days allows adequate time for GO to interact with manufacturers and examine capabilities of equipment. In establishing this timeframe, the DT considered the PRC-004 timeline of 120 days, recognizing important differences between the application of these standards. PRC-004-4(i) Technical Rationale states "The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed".[3] The PRC-004 timeframe accounts for extreme weather events such as hurricanes that may affect a very large number of Protection Systems for a given responsible entity. The volume of IBR exposed to potential expected operation is anticipated to be lower when compared to Protection Systems and therefore a shorter timeframe is appropriate for PRC-030. The 90-day period starts from the event date for GO-identified performance issues resulting from Requirement R1 or upon request from the Balancing Authority, Reliability Coordinator, or Transmission Operator regarding IBR responses identified during system events.

Requirement R2, Part 2.1 includes subparts to analyze performance during a Real power change event. Requirement R2, Part 2.1.1 requires identification of the root cause. Requirement R2, Part 2.1.2 requires that the facility's Ride-through performance including reactive power response is documented (Requirement R2, Part2.1.2). Requirement R2, Part 2.1.3 requires that the GO assess the performance issue(s) and determine whether corrective actions are needed. Requirement R2, Part 2.1.4 requires that the GO consider the applicability of the root cause to its other IBR facilities. Collectively, the subparts define the minimum features required as part of an effective analysis. Requirement R2, Part 2.2 closes the communication loop with Balancing Authority, Reliability Coordinator, and Transmission Operator entities, should these entities request analysis results.

When the root cause cannot be identified or a root cause is identified but the GO cannot fully mitigate it, then it is expected the GO will continue to work with the associated reliability entities and Original Equipment Manufacturers to follow up on such instances and deploy mitigation plans when these become available. The GO will continue to coordinate with associated reliability entities through improvements to root cause analysis and CAPs until such a time the mitigation plans are in place. Such improvements include better data capture, and fault logging capabilities for subsequent future events.

[3] Standard PRC-004-4(i) – Protection System Misoperation Identification and Correction. Available at: https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-004-4(i).pdf

Rationale for Requirement R3

Should Requirement R2 determine a need for corrective actions, Requirement R3 requires a CAP or technical justification be developed within 60 calendar days of completing the analysis in Requirement R2, as identified in Requirement R2, Part 2.1.3. If Requirement R2 did not identify the need for corrective actions, then no action is required under Requirement R3.

Resolving the causes of IBR performance issues benefits BPS reliability by preventing recurrence. The CAP is an established tool for resolving operational problems. The NERC *Glossary* defines a Corrective Action Plan as, "A list of actions and an associated timetable for implementation to remedy a specific problem." Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the IBR Performance issue cause(s) is identified in Requirement R2 or Requirement R3 requires Generator Owner(s) to develop a CAP or provide a technical justification that addresses why corrective actions will not be applied nor implemented. The CAP is provided to the Reliability Coordinator, Balancing Authority, and Transmission Operator so that these entities 1) gain information potentially relevant to recent system events, and 2) can account for potential IBR performance issues in operational risk assessments.

This standard recognizes there may be multiple causes for IBR performance issues. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a CAP to correct multiple causes of an IBR performance issue. The 60-calendar day period for developing a CAP or technical justification is established based on industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent IBR performance issues from reoccurring, the timetable for executing such actions, and an evaluation of the CAP's applicability to the GO's other IBR including those at other locations. The evaluation of these other IBR with similar designs aims to reduce the risk and the likelihood of similar IBR performance issues in other IBRs. The GO is responsible for determining the extent of its evaluation concerning other IBRs and locations. The evaluation may result in the GO including actions to address IBR at other locations or to provide a technical justification that addresses why corrective actions will not be applied nor implemented.

Acceptable technical justification for not performing corrective actions is expected to primarily have two characteristics:

1) interconnection requirements on IBR performance extending beyond those in place at the time of interconnection; and
2) it would require significant material modifications/qualified change.

Technical justifications for not performing corrective actions do not relieve the GO from compliance with other standards (i.e., PRC-029-1 Ride-Through) to the extent that other standards are applicable.

Rationale for Requirement R4

Requirement R4 requires that each applicable GO implement the CAP developed in Requirement R3, as applicable, to mitigate deficiencies identified in Requirement R2. In the NERC *Glossary*, a CAP is: “A list of actions and an associated timetable for implementation to remedy a specific problem.”

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. If the CAP is changed, the entity must notify the applicable Reliability Coordinator(s). The entity must also notify applicable RC(s) when the CAP has been completed. The implementation of a properly developed CAP ensures that causes of unexpected changes in IBR power output are mitigated in a timely manner.

An IBR deficiency may require the Reliability Coordinator to impose operating restrictions so the system can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions should incentivize the entity to complete the CAP as quickly as possible.

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Exhibit F

Analysis of Violation Risk Factors
and Violation Severity Levels

Violation Risk Factor and Violation Severity Level Justifications

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

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 Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues. 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 Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric 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 Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric 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 Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric 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 Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric 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 Electric System, or the ability to effectively monitor and control the Bulk Electric 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 Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric 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-030-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because not having a process for identifying changes in Real Power output, which is required in defining the minimum standards will be performed, could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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 medium 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-030-1, Requirement R1	
Proposed VRF	**Medium**
than One Obligation	

VSLs for PRC-030-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity failed to implement a documented process to identify changes in Real Power output in accordance with Requirement R1.

VSL Justifications for PRC-030-1, 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.
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-030-1, Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because a Generator Owner not analyzing it's Inverter Based Resource's performance which are required in defining the minimum standards will be within 90 days of an event, identified pursuant to Requirement R1 or receipt of a request pursuant to Requirement R2, to address the unexpected change(s) in power output and the applicability to its other IBR facilities that could be affected by the same cause of unexpected change(s) in power output could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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	This VRF is in line with the definition of a medium VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-030-1, Requirement R2	
Proposed VRF	**Medium**
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-030-1, Requirement R2

Lower	Moderate	High	Severe
The responsible entity performed an analysis in accordance with Requirement R2, but in more than 90 calendar days but less than 120 calendar days of an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 120 or more calendar days but less than 150 calendar days of an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 150 or more calendar days but less than 180 calendar days of an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 or Part 2.1.4. OR The responsible entity failed to provide the analysis results from the requesting entity in accordance with Requirement R2, Part 2.2.	The responsible entity developed an analysis in accordance with Requirement R2, but in 180 calendar days or more of an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 and Part 2.1.4. OR The responsible entity failed to document the facility's Ride-through performance in accordance with Requirement R2, Part 2.1.2 OR

			The responsible entity failed to determine the applicability of other Inverter-Based Resource facilities in accordance with Requirement R2, Part 2.1.4.

VSL Justifications for PRC-030-1, 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 not 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	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for PRC-030-1, Requirement R2	
Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF Justifications for PRC-030-1, Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because a Generator Owner's failure to develop either a Corrective Action Plan (CAP), or technical justification that addresses why corrective actions will not be applied nor implemented for it's Inverter Based Resource's could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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 medium VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-030-1, Requirement R3	
Proposed VRF	**Medium**
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-030-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 60 calendar days, but provided it within 90 calendar days.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 90 calendar days, but provided it within 120 calendar days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 120 calendar days, but provided it within 150 calendar days OR The developed CAP did not include corrective actions for other facilities owned by the Generator Owners as identified in Requirement R2 Part 2.1.3, if necessary. OR The developed CAP or technical justification was not provided to the associated Reliability	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented, within 150 calendar days.

		Coordinator, Balancing Authority, and Transmission Operator.	

VSL Justifications for PRC-030-1, 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 not 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-030-1, Requirement R3	
Number of Violations	

VRF Justifications for PRC-030-1, Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because failure to implement, update, or notify with the applicable Reliability Coordinator (RC) the Corrective Action Plan (CAP) for it's Inverter Based Resource's could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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 medium 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-030-1, Requirement R4	
Proposed VRF	**Medium**
than One Obligation	

VSLs for PRC-030-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R4.

VSL Justifications for PRC-030-1, 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	The proposed VSLs are not 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-030-1, 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.

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Exhibit G

Summary of Development History
and Complete Record of Development

Summary of Development History

The following is a summary of the development record for proposed Reliability Standard PRC-030-1 developed under Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues.

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 drafting team ("DT") selected to lead each project in accordance with Section 4.3 of the NERC Standard Processes Manual.[2] For this project, the DT consisted of industry experts, all with a diverse set of experiences. A roster of the Project 2023-02 DT members is included in **Exhibit H**.

II. Standard Development History

A. Standard Authorization Request Development

In December 2022, the NERC Inverter-based Resource Performance Subcommittee ("IRPS") submitted a Standard Authorization Request ("SAR") to address reliability gaps identified in Inverter-Based Resource ("IBR") performance during disturbances.[3] At its January 25, 2023 meeting, the NERC Standards Committee accepted the SAR, authorized posting for 30-day informal comment period, and authorized solicitation of DT members.[4] NERC initiated Project 2023-02, Analysis and Mitigation of BES Inverter-Based Resource Performance Issues to address the issues identified in the SAR.

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1 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. § 824(d)(2) (2024).

2 The NERC *Standard Processes Manual* is available at https://www.nerc.com/AboutNERC/RulesOfProcedure/Appendix_3A_SPM_Clean_Mar2019.pdf.

3 Exhibit G at Item 1.

4 NERC, *Minutes – Standards Committee Meeting Jan. 25, 2023*, Agenda Item 6 (Inverter-based Resources Performance Standard Authorization Request), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/January%20Meeting%20Minutes%20-%20Approved%20February%2022,%202023.pdf.

The SAR was posted from February 22 – March 23, 2023, along with a solicitation for DT members. At its June 21, 2023 meeting, the Standards Committee appointed the SAR Drafting Team as the Standard Drafting Team ("SDT").[5] At its October 18, 2023 meeting, the Standards Committee accepted the revised SAR and authorized drafting revisions to the standard.[6]

B. Waiver

The Standards Committee approved waivers of Standard Processes Manual minimum posting length requirements for Project 2023-02 on December 13, 2023, authorizing initial formal comment to be reduced from 45 to as few as 25 days, additional formal comment and ballot periods to be reduced from 45 days to as few as 15 calendar days, with ballot conducted during the last 10 days of the comment period.[7] Additionally, the final ballot was authorized to be reduced to as few as 5 calendar days. NERC Staff sought these waivers to assist the drafting team in meeting the firm timeline expectations set by FERC Order 901.

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

A draft of proposed Reliability Standard PRC-030-1 was initially posted from March 25, 2024 – April 18, 2024. The initial ballot was conducted between April 9, 2024 – April 18, 2024 and failed to achieve the required ballot body approval. There were 66 sets of responses, including comments from approximately 180 different individuals and approximately 120 companies,

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[5] NERC, *Minutes – Standards Committee Meeting June 21, 2023*, Agenda Item 5 (Project 2023-02 Performance of IBRs), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/June%20Meeting%20Minutes%20-%20Approved%20July%2019,%202023.pdf.

[6] NERC, *Minutes – Standards Committee Meeting October 18, 2023*, Agenda Item 5 (Project 2023-02 Performance of IBRs), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC%20October%20Minutes%20-%20Approved%20November%2015,%202023.pdf.

[7] NERC, *Minutes – Standards Committee Meeting Dec. 13, 2023*, Agenda Item 9 (Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Waiver), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC%20December%20Minutes%20-%20Approved%20January%2017,%202024.pdf.

representing all 10 industry segments.[8] The following table provides: 1) the percentage of affirmative votes,[9] 2) the quorum reached, and 3) the results of the non-binding poll and quorum for the associated VRFs and VSLs.

Standard	Approval	Quorum	Non-binding Poll / Quorum
PRC-030-1	21.19%	92.78%	13.11% / 90.08%
Implementation Plan	30.60%	92.81%	N/A

D. Second Posting - Comment Period, Additional Ballot, and Non-binding Poll

A revised draft of proposed Reliability Standard PRC-030-1, the associated Implementation Plan, VRFs, VSLs, and other associated documents were posted for an additional formal comment period from June 7, 2024 – July 10, 2024, with a ballot conducted July 1, 2024 – July 10, 2024.

There were 49 sets of responses, including comments from approximately 152 different individuals and approximately 101 companies, representing all 10 industry segments.[10] The following table provides: 1) the percentage of affirmative votes, 2) the quorum reached, and 3) the results of the non-binding poll and quorum for the associated VRFs and VSLs.

Standard	Approval	Quorum	Non-binding Poll/Quorum
PRC-030-1	31.44%	81.95%	24.68% / 78.63%
Implementation Plan	41.50%	81.65%	N/A

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

A revised draft of proposed Reliability Standard PRC-030-1, the associated Implementation Plan, VRFs, VSLs, and other associated documents were posted for an additional

8 NERC, *Consideration of Comments – 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues | Draft 1*, Exhibit G at Item 18.

9 A ballot needs 66 and two-thirds percentage approval to pass.

10 NERC, *Consideration of Comments - 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues | Draft 2*, Exhibit G at Item 34.

formal comment period from July 22, 2024 – August 12, 2024, with a ballot conducted August 2, 2024 – August 12, 2024.

There were 60 sets of responses, including comments from approximately 151 different individuals and approximately 105 companies, representing all 10 industry segments.[11] The following table provides: 1) the percentage of affirmative votes, 2) the quorum reached, and 3) the results of the non-binding poll and quorum for the associated VRFs and VSLs.

Standard	Approval	Quorum	Non-binding Poll/Quorum
PRC-030-1	76.11%	90.61%	70.55% / 90.08%
Implementation Plan	85.20%	89.93%	N/A

F. Fourth Posting - Comment Period, Additional Ballot, and Non-binding Poll

While the standard achieved approval in the third posting, the SDT decided to make additional substantive changes to the draft following ballot, and it was posted for another additional comment period from August 28, 2024 – September 13, 2024, with a ballot conducted September 4, 2024 – September 13, 2024, where it achieved the required ballot body approval.

There were 45 sets of responses, including comments from approximately 129 different individuals and approximately 93 companies, representing all 10 industry segments.[12] The following table provides: 1) the percentage of affirmative votes, 2) the quorum reached, and 3) the results of the non-binding poll and quorum for the associated VRFs and VSLs.

Standard	Approval	Quorum	Non-binding Poll/Quorum
PRC-030-1	69.73%	88.09%	63.25% / 85.50%
Implementation Plan	74.56%	88.13%	N/A

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[11] NERC, *Consideration of Comments - 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues | Draft 3*, Exhibit G at Item 51.

[12] NERC, *Consideration of Comments - 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues | Draft 4*, Exhibit G at Item 68.

G. Final Ballot

The proposed Reliability Standard, the associated Implementation Plan, VRFs, VSLs, and other associated documents were posted for a 5-day final ballot from September 23, 2024 – September 27, 2024. The following table provides for the Reliability Standard: 1) the percentage of affirmative votes, and 2) the quorum reached.

Standard	Approval	Quorum
PRC-030-1	70.88%	90.61%
Implementation Plan	74.78%	90.65%

H. Board of Trustees Adoption

The NERC Board of Trustees adopted the proposed Reliability Standard on October 8, 2024.[13]

[13] NERC, *Board of Trustees Agenda Package*, Agenda Item 2d (Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues) (Oct. 8, 2024), https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board%20of%20Trustees%20Open%20Meeting%20Agenda%20Package%20October%208%202024%20Attendees.pdf.

Complete Record of Development

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

Related Files

Status

The final ballot for **PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation** concluded **8 p.m. Eastern, Friday, September 27, 2024**. The ballot results can be accessed via the links below. The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

The Standards Committee approved waivers to the Standards Process Manual at their December 2023 meeting. These waivers were sought to allow for reduced formal comment and ballot periods to assist the drafting team in expediting the 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 the comment and ballot period, NERC 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.

Background

Multiple NERC disturbance reports,[1] including the Odessa disturbance report,[2] have identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that this undesired performance can pose. IBRs may trip for many different reasons, may cease current injection due to inverter controls, or may have unwanted plant-level controller interactions. These types of issues have been extensively documented in the NERC reports. The resulting unexpected and unwarranted loss of generation poses a significant risk to BPS reliability.

Standard Affected: PRC-004-6

Purpose/Industry Need

This project addresses the reliability-related need and benefit by requiring analysis and mitigation of unexpected or unwarranted protection and control operations from inverter-based resources following the identification of such a performance issue. This includes any types of protections or controls that result in abnormal performance issues within the plant, including abnorma performance resulting in anomalous behavior of active power output from the facility during events. Considerations may be needed for legacy facilities, but the root cause analysis of the abnorma performance and determination of any mitigating measures should be conducted. The SAR should be applicable to all Bulk Electric System (BES) inverter-based generating resources, includinc battery energy storage resources.

These changes will prompt analysis of IBR loss events following grid disturbances to ensure that facilities are operating in a reliable manner and providing essential reliability services. Mitigating actions will reduce unnecessary IBR tripping or controls issues that result in widespread reduction of power output from these facilities, and will also reduce the possibility of systemic performance issues in the future.

[1] https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx

[2] https://www.nerc.com/pa/rrm/ea/Pages/May-June-2021-Odessa-Disturbance.aspx

Subscribe to this project's observer mailing list

Select "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues" in the Description Box.

Draft	Actions	Dates	Results	Consideration of Comments
Final Ballot PRC-030-1 Clean **(74)** | Redline to Last Posted **(75)** Implementation Plan Clean **(76)** | Redline **(77)** **Supporting Materials** Technical Rationale Clean **(78)** | Redline **(79)** VRF/VSL Justifications Clean **(80)** | Redline **(81)**	Final Ballot Info **(82)** Vote	09/23/24 - 09/27/24	Ballot Results PRC-030-1 **(83)** Implementation Plan **(84)**	
Draft 4 **PRC-030-1** Clean Updated **(57)** | Redline to Last Posted Updated **(58)** Implementation Plan Clean**(59)** | Redline to Last Posted **(60)** **Supporting Materials**	Additional Ballots Ballot Open Reminder **(69)** Info **(70)** Vote	9/4/24 - 9/13/24	Ballot Results PRC-030-1 **(71)** Implementation Plan **(72)** Non-binding Poll **(73)**	

Technical Rationale Clean **(61)** | Redline to Last Posted **(62)** Unofficial Comment Form **(63)** VRF/VSL Justifications Updated **(64)** Mapping Document **(65)**	Comment Period Info **(66)** Submit Comments	8/28/24 - 9/13/24	Comments Received **(67)**	Consideration of Comments **(68)**
Draft 3 **PRC-030-1** Clean **(40)** | Redline to Last Posted **(41)** Implementation Plan Clean **(42)** | Redline to Last Posted **(43)** **Supporting Materials** Technical Rationale Clean **(44)** | Redline to Last Posted **(45)** Unofficial Comment Form **(46)** VRF/VSL Justifications **(47)** Mapping Document **(48)**	Additional Ballots Ballot Open Reminder **(52)** Info **(53)** Vote	8/2/24 - 8/12/24	Ballot Results PRC-030-1 **(54)** Implementation Plan **(55)** Non-binding Poll Results **(56)**	
	Comment Period Info **(49)** Submit Comments	7/22/24 - 8/12/24	Comments Received **(50)**	Consideration of Comments **(51)**
Draft 2 **PRC-030-1** Clean **(25)** | Redline to Last Posted **(26)** Implementation Plan Clean **(27)** | Redline to Last Posted **(28)** **Supporting Materials** Technical Rationale **(29)** Unofficial Comment Form **(30)** VRF/VSL Justifications **(31)**	Additional Ballots Ballot Open Reminder **(35)** Info **(36)** Vote	7/1/24 - 7/10/24	Ballot Results PRC-030-1 **(37)** Implementation Plan **(38)** Non-binding Poll Results **(39)**	
	Comment Period Info **(32)** Submit Comments	6/7/24 - 7/10/24	Comments Received **(33)**	Consideration of Comments **(34)**
Draft 1 **PRC-030-1 (11)** Implementation Plan **(12)** **Supporting Materials** Technical Rationale **(13)** Unofficial Comment Form **(14)** VRF/VSL Justifications **(15)**	Initial Ballot Ballot Open Reminder **(20)** Info **(21)** Vote	4/9/24 - 4/18/24	Ballot Results PRC-030-1 **(22)** Implementation Plan **(23)** Non-binding Poll Results **(24)**	
	Join Ballot Pools Ballot Pool Reminder **(19)**	3/25/24 - 4/3/24		
	Comment Period			

	Info (16) Submit Comments	3/25/24 - 4/18/24	Comments Received (17)	Consideration of Comments (18)
Waiver (10)	Standards Committee accepted the waiver on December 13, 2023.	12/13/2023		
Standard Authorization Request Clean (8) | Redline (9)	Accepted by the Standards Committee			
Drafting Team Nominations **Supporting Materials** Unofficial Nomination Form (Word) (6)	Nomination Period Info (7) Submit Nominations	2/22/2023 - 3/23/2023		
Standard Authorization Request (1) **Supporting Materials** Unofficial Comment Form (Word) (2)	Comment Period Info (3) Submit Comments	2/22/2023 - 3/23/2023	Comments Received (4)	Consideration of Comments (5)

Atlanta Office | 3353 Peachtree Road, NE Suite 600 North Tower, Atlanta, GA 30326 | 404-446-2560
Washington Office | 1401 H Street NW, Suite 410, Washington, DC 20005| 202-400-3000

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:	Analysis and Mitigation of BES Inverter-Based Resource Performance Issues		
Date Submitted:	12/06/2022		
SAR Requester			
Name:	Julia Matevosyan, ESIG, IRPS Chair Rajat Majumder, Orsted, IRPS Vice Chair		
Organization:	NERC Inverter-based Resource Performance Subcommittee (IRPS)		
Telephone:	Julia – 512-994-7914 Rajat – 321-390-0333	Email:	julia@esig.energy RAMAJ@orsted.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?):			
Multiple NERC disturbance reports[1] have identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that these pose. These are strongly highlighted in the recent disturbance reports from 2021 including the Odessa disturbance report.[2] IBRs may trip for many different reasons, may cease current injection due to inverter controls, or may have unwanted plant-level controller interactions. These types of issues have been extensively documented in the NERC reports. The resulting unexpected and unwarranted loss of generation poses a significant risk to BPS reliability.			

[1] https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx
[2] https://www.nerc.com/pa/rrm/ea/Pages/May-June-2021-Odessa-Disturbance.aspx

Requested information
Unlike synchronous generation, IBRs can reduce power output very quickly based on the power electronic controls and protections, and the reduction does not necessarily require the operation of an ac circuit breaker or other Protection System (as defined by the NERC Glossary of Terms). The current PRC-004 is focused mainly on conventional Protection Systems and ensures that misoperations are analyzed and mitigated. However, this type of analysis and mitigation is not occurring for inverter-based resources for the reasons described above, and has led to the systemic performance issues documented in NERC disturbance reports. Rather than complicate the existing PRC-004 focused on Protection Systems, IRPS believes that a new standard should be developed specific to IBRs to ensure that any unexpected ceasing of current injection (partial or full) is analyzed by the applicable Generator Owner and mitigated to the extent possible. NERC has also highlighted that many Generator Owners are not aware of these trips, and that the Balancing Authority or Reliability Coordinator may often identify the unexpected or unwarranted tripping issues. Therefore, it is important that the BA or RC have the authority to identify abnormal performance issues which should then initiate analysis and mitigations by the GO. To be clear, the SAR is not proposing that the BA or RC is responsible for identifying these events; rather, the SAR is proposing that the BA and RC have the ability and authority to voluntarily initiate analysis of the abnormal performance issues by the asset owner (i.e., the GO). It is important that the GO is accountable for analyzing these events, has necessary monitoring equipment installed, and cooperates with the BA/RC by providing operational data and analytical results. Some legacy equipment may not be able to mitigate performance issues; however, these events should be analyzed with root causes of misoperation identified and possible mitigating actions (or lack thereof) should be documented for all applicable parties.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The purpose of this proposed project is to introduce a new standard or modify the existing PRC-004 standard[3] that requires analysis and mitigation of unexpected or unwarranted protection and control operations from inverter-based resources following the identification of such a performance issue. This will ensure that IBR loss events (either through protection or control actions) such as those that have occurred numerous times as documented in the NERC disturbance reports are included in the types of events that must be analyzed and mitigated. Considerations will be given for legacy equipment; however, analysis and documentation of mitigation actions (where possible) should still occur. The project should clarify that any protections and controls within an IBR facility that causes abnormal performance of the facility should be included in this type of analysis. These changes will prompt analysis of IBR loss events following grid disturbances to ensure that facilities are operating in a reliable manner and providing essential reliability services. Mitigating actions will reduce unnecessary IBR tripping or controls issues that result in widespread reduction of power output from these facilities, and will also reduce the possibility of systemic performance issues in the future.

[3] IRPS recommends the development of a new standard; however, this is left up to the drafting team to develop an appropriate solution.

Requested information
Project Scope (Define the parameters of the proposed project):
The scope of this project is to either create a new NERC reliability standard or modify an existing standard[4] that requires IBRs that respond to grid disturbances in an unexpected, unwarranted, and unreliable manner to identify, analyze, and mitigate performance issues that occur within the facility. This includes any types of protections or controls that result in abnormal performance issues within the plant, including abnormal performance resulting in anomalous behavior of active power output from the facility during events. Considerations may be needed for legacy facilities, but the root cause analysis of the abnormal performance and determination of any mitigating measures should be conducted. The IRPS also included the possibility of adding new or modifying existing NERC Glossary Terms, as the drafting team determines necessary, to ensure clarity in the standard. Battery energy storage resources, as generating resources, should also be included in the scope of this project. The SAR should be applicable to all BES inverter-based generating resources.
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[5] 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):
Rather than attempt to significantly modify PRC-004 and change the definition of Protection System, the IRPS believes the best approach is to develop a new NERC standard focused specifically on identifying, analyzing, and mitigating unexpected/abnormal performance issues at IBR facilities. The proposed standard does not intend to modify the existing Protection System definition or PRC-004 since the IRPS knows that this will be extremely complicated and could overcomplicate the matter. The NERC reports highlight the strong need for more proactive analysis of IBR performance issues by facility owners. The past few NERC disturbance reports have highlighted limited awareness and understanding by facility owners that abnormal performance has even occurred, and therefore identification of possible performance issues should be initiated by either the IBR facility owner/operator (i.e., the GO/GOP) or by the transmission entities with a wide-area view (i.e., the TOP, RC, or BA). However, the onus of analysis and development of mitigating actions should be on the asset owner to eliminate the possible risk of repeated abnormal performance issues. IRPS recognizes that legacy equipment may not be able to eliminate or fully mitigate performance issues at those facilities; however, analysis and determination of any possible mitigations should be explored and reported to the TOP, RC, and BA and documented by the GO/GOP. This will ensure that possible mitigating actions are fully explored and communicated to all necessary parties.

[4] This is left up to the standard drafting team to ensure sufficient flexibility in developing an appropriate solution. IRPS recommends the creation of a new NERC Standard focused specifically on IBR-specific issues so as to avoid conflating these issues with conventional protection systems installed across transmission networks.

[5] 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
IRPS believes that all BES IBR generating facilities should be applicable to this standard as these issues have been observed across generators of varying sizes (including numerous resources lower than the BES threshold). Therefore, it would not seem logical to raise the size threshold any higher than the BES definition for dispersed power producing resources. IRPS believes that the issues requiring analysis should include any protection or controls that result in abnormal or unexpected performance of the resource for any reason. While every possible abnormal performance issue may not be picked up by the GO, GOP, or any transmission entity, any abnormal performance issue identified could result in analysis and possible mitigation. Momentary cessation and IBR tripping for external grid faults should be included in this analysis. Delayed active power recovery following fault ride-through events beyond any applicable standard or mutually agreement should be included in this analysis. Abnormal IBR unit- or plant-level control actions should be included in this analysis. These are all considered unwanted, unexpected, and abnormal and should be explored for corrective actions. The causes of abnormal changes in power output during events (e.g., faults) should include any protections and controls within the IBR, the plant-level controller, and any protection systems within the plant. IRPS believes that the drafting team should have the flexibility to determine appropriate solutions (i.e., standards language) to codify these concepts in a new NERC Standard. The drafting team may want to explore reporting criteria that avoids unnecessary redundant reporting yet can adequately capture any new performance issues if/when they occur. IRPS would also like to point out that the NERC reports have highlighted that the protection/controls that “operate as they are programmed” does not necessarily mean correct operation as per interconnection requirements. When a plant trips off-line for an external fault for reasons that are not expected (or allowed per interconnection requirements) nor are likely modeled appropriately in planning assessments, these types of abnormal reductions (tripping, controls, or controller interactions) should be analyzed and mitigated by the GO/GOP in a timely manner. This will likely require the engagement of equipment manufacturers and adequate monitoring data to perform root cause analysis.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The new standard will require Generator Owners to analyze performance issues identified at their facilities, which may require some engineering and analytical capabilities and additional coordination with equipment manufacturers to determine possible mitigating measures. This type of activity is conducted by all transmission entities, and more commonly conducted by synchronous generator owners (due to the clear operation of an ac circuit breaker tripping a large amount of power with little to no automatic reconnection). Some additional monitoring equipment and capability may be needed at the GO facilities to determine root causes of abnormal performance. Due to the systemic nature of risks posed by these issues, the reliability benefits are expected to outweigh the costs for this effort.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):

Requested information
The proposed standard project is focused specifically on identifying, analyzing, and mitigating reliability issues for BES inverter-based 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):
The Functional Entities that the proposed standard would apply to are the inverter-based resource Generator Owners. This standard will also give authority to the RC, TOP, or BA to initiate an analysis by a GO if abnormal performance issues are identified. Additional entities that may provide value to the standard drafting efforts include GOPs, RCs, BAs, TOPs, TPs, and PCs.
Do you know of any consensus building activities[6] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This SAR was developed by the NERC IRPS, a consensus-based subcommittee of the NERC Reliability and Security Technical Committee (RSTC). The IRPS developed a white paper[7] as a follow-up to the Odessa disturbance that highlighted the need for this SAR; that white paper was also approved by the RSTC.
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)?
N/A
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 disturbance reports have highlighted the need for improved analysis of systemic performance issues from inverter-based resources. NERC IRPS has published numerous guidelines and reports to support industry with recommended monitoring points, performance issues, etc. These activities have not addressed the risk that inverter-based resource owners are not identifying, analyzing, and mitigating abnormal performance issues.

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.

[6] 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.
[7] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Odessa_Disturbance_Follow-Up.pdf

Reliability Principles	
☐	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
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 2023-02 Performance of IBRs

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2023-02 Performance of IBRs Standard Authorization Request (SAR)** by **8 p.m. Eastern, Thursday, March 23, 2023.**

Additional information is available on the project page. If you have questions, contact Standards Developer, Dominique Love (via email), or at 404-217-7578.

Background Information

This project addresses the reliability-related need and benefit by requiring analysis and mitigation of unexpected or unwarranted protection and control operations from inverter-based resources following the identification of such a performance issue. This includes any types of protections or controls that result in abnormal performance issues within the plant, including abnormal performance resulting in anomalous behavior of active power output from the facility during events. Considerations may be needed for legacy facilities, but the root cause analysis of the abnormal performance and determination of any mitigating measures should be conducted. The SAR should be applicable to all Bulk Electric System (BES) inverter-based generating resources, including battery energy storage resources.

These changes will prompt analysis of IBR loss events following grid disturbances to ensure that facilities are operating in a reliable manner and providing essential reliability services. Mitigating actions will reduce unnecessary IBR tripping or controls issues that result in widespread reduction of power output from these facilities, and will also reduce the possibility of systemic performance issues in the future. The result will produce one deliverable:

- Modifications to PRC-004 (or a new standard) – focus on IBRs to ensure that any unexpected ceasing of current injection (partial or full) is analyzed by the applicable Generator Owner and mitigated to the extent possible.

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:

Comment Report

Project Name:	2023-02 Performance of IBRs | SAR
Comment Period Start Date:	2/22/2023
Comment Period End Date:	3/23/2023
Associated Ballots:	

There were 41 sets of responses, including comments from approximately 130 different people from approximately 91 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
BC Hydro and Power Authority	Adrian Andreoiu	1,3,5	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
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	MRO,SPP RE,WECC	SRC 2023	Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	1	WECC
					Helen Lainis	IESO	1	NPCC
					Matt Goldberg	ISONE	1	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Greg Campoli	NYISO	1	NPCC
					Elizabeth Davis	PJM	2	RF
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
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
MRO	Jou Yang	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Chris Bills	City of Independence, Power and Light Department	5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bryan Sherrow	Board of Public Utilities	1	MRO
					Terry Harbour	Berkshire Hathaway Energy - MidAmerican Energy Co.	1	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO

					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shonda McCain	Omaha Public Power District	6	MRO
					George E Brown	Pattern Operators LP	5	MRO
					George Brown	Acciona Energy USA	5	MRO
					Jaimin Patel	Saskatchewan Power Cooperation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jay Sethi	Manitoba Hydro	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
DTE Energy - Detroit Edison Company	Karie Barczak	3,5		DTE Energy - DTE Electric	Adrian Raducea	DTE Energy - Detroit Edison Company	5	RF
					Patricia Ireland	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
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
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	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

					Frank Lee	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
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
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
					Sheraz Majid	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Chantal Mazza	Hydro Quebec	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Dan Kopin	Vermont Electric Power Company	1	NPCC

					James Grant	NYISO	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Randy MacDonald	New Brunswick Power Corporation	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
					Glen Smith	Entergy Services	4	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
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Bryan Wood	Southwest Power Pool Inc	2	MRO
					Brian Strickland	Southwest Power Pool Inc	2	MRO
					Derek Hawkins	Southwest Power Pool Inc.	2	MRO
					Margaret Quispe	Southwest Power Pool Inc.	2	MRO
					Mia Wilson	Southwest Power Pool Inc.	2	MRO

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.

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The MRO NSRF provides the following comments:

1. Need to eliminate references to trip, tripping, and Protection System in this SAR – those parts of IBRs are already covered sufficiently (included and subject to the standard) by the existing PRC-004.

2. A new standard is definitely better to address the control system performance evaluation.

3. The BA, TOP, and RC should play a part in determining what disturbances are significant and justifiably warrant analysis. Further, an analysis and report by the GO/GOP to the BA, TOP, and RC can be specified in the existing TOP-003 and IRO-010 standards, rendering that part of the SAR unneeded. Those standards give authority already. A GO alone developed criterion may result in analysis of very insignificant (single facility) events.

4.Thoughts on legacy equipment:

Some recognition of the limitations of existing equipment needs to be addressed in the proposed scope to eliminate all performance issues through mitigation plans. This could be done by adding "where possible" to the phrase "…identify, analyze, and mitigate performance issues where possible.

Use of unwarranted – there are times where the performance (cease conduction) is very much warranted – some at NERC do not seem to understand this – (e.g., loss of synchronizing signal – no alternate control modes – processor speed limitations – control algorithm limitations)

The repeated characterization all inverter performance behavior as "unexpected", "abnormal", "unwarranted", "anomalous" does not correctly represent the behavior of controls that were neither designed nor built to be able to ride-thru the system disturbances to which they are being subjected. Through the repeated evaluation of events and multiple control parameter setting changes performed over the past five (5) years, the behavior observed is as expected, deemed normal, and completely warranted depending upon the legacy and capabilities of the particular inverter.

A distinction between "operating as they are programmed" and "operating within the design characteristics of the control system" needs to be recognized and respected. Certain legacy equipment has constraints and cannot be made to be able to ride through all system disturbances. There is little value in this standard requiring repeated identification, analysis, and possible mitigation evaluation for plants that have adjusted all possible parametric options for the desensitization to system conditions and for the fastest possible recovery time.

5. "Abnormal performance" must be defined both in the SAR and then officially in the Glossary of Terms Used in NERC Reliability Standards. Without a definition the SAR and subsequent draft standard will fail to achieve the need of the project. The MRO suggests the SAR drafting team develop a list of 'abnormal performance' issues, which will focus the scope of the SAR and provide a starting point for the Standards Drafting Team.

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 scope and submits the following comments for consideration: a) The NAGF notes that the existing Reliability Standard PRC-004-06: Protection System Misoperation Identification and Correction already addresses BES IBR protection systems/components. Therefore, the NAGF recommends to remove references to “protections” in the Project Scope section. b) The NAGF recommends the first sentence of the Project Scope section be modified as follows: “...and unreliable manner to identify, analyze, and mitigate performance issues *to the extent possible* that occur within the facility.” c) All BES IBR battery energy storage resources, whether they as considered generator or transmission resources, should be applicable to this standard. Therefore, the NAGF recommends removing or amending the sentence regarding battery energy storage resources.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	No
Document Name	
Comment	
Tri-State mostly agrees with the SAR, however recommends that references to updating the existing PRC-004 (or other standards) be removed from the SAR. A new standard should be created for Inverter Based Resources.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	No
Document Name	
Comment	

Constellation Generation feels the creation of a new standard to address only IBR's is unnecessary and overly burdensome when existing standards could address IBR's and in many cases already do. The SAR mentions "current cessation" and other limited capabilities that could be addressed in existing standards such as PRC-019 and PRC-024, rather than creation of a new and duplicative standard.

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 Generation feels the creation of a new standard to address only IBR's is unnecessary and overly burdensome when existing standards could address IBR's and in many cases already do. The SAR mentions "current cessation" and other limited capabilities that could be addressed in existing standards such as PRC-019 and PRC-024, rather than creation of a new and duplicative standard.

Alison Mackellar on behalf of Constellation Segments 5 and 6

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 supports the MRO NSRFs comments.

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	No
Document Name	
Comment	
The ISO/RTO Council (IRC) Standards Review Committee (SRC) agrees with the general scope of the project, but has recommendations to help ensure these requirements are effective and non-duplicative with other IBR projects currently underway. Our response to Question 2 provides recommendations.	
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 Standards Review Committee (SRC).	
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	
Tacoma Power has no comments.	
Likes 0	
Dislikes 0	
Response	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF	

Answer	Yes
Document Name	
Comment	

Response Created in error- please delete

Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6

Answer	Yes
Document Name	
Comment	

AZPS supports the proposed SAR and agrees with the IRPS that a new Reliability Standard should be developed to specifically address IBR performance.

Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1,3,5,6

Answer	Yes
Document Name	
Comment	

Currently, Manitoba Hydro does not have any IBRs, but likley will in the future.

Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer	Yes
Document Name	

Comment	
BC Hydro agrees with IRPS that a new Reliability Standard specific to IBRs performance should be developed.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy agrees with the scope of the SAR.	
Likes 0	
Dislikes 0	
Response	
Lori Frisk - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	

None.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 3,5,6	
Answer	Yes
Document Name	

Comment
AEP agrees with the perceived reliability need expressed in this SAR and agree with the authors that it would be inadvisable to revise PRC-004, as among other reasons, the scope of PRC-004 would need to be expanded to cover ride-through issues that may not be classifiable as protection misoperation. We also agree that an entirely new standard would be the preferred means to meet the objectives of the SAR. In addition, we suggest that consideration also be given to perhaps sharing this SAR with the Project 2020-02 drafting team for it to possibly augment their efforts rather than having the "Analysis and Mitigation of BES Inverter-Based Resource Performance Issues" SAR have its own distinct project (2023-02). If a new standard were to be written under 2023-02, it could end up a parallel effort to Project 2020-02 (PRC-024) which is now under revision by a project that specifically aims to convert it from a relay setting standard into a true ride-through standard. Identification, analysis, and mitigation of abnormal, unexpected, and unwarranted IBR behaviors affecting ride-through performance, which is what this SAR proposes to require, are actions that would necessarily be subsumed into any ride-through requirements. In any event, care needs to be taken to ensure that no efforts are duplicative across projects and/or standards.

Likes 0	
Dislikes 0	

Response

Wesley Yeomans - New York State Reliability Council - 10	
Answer	Yes
Document Name	

Comment
The Scope requires IBRs to "identify, analyze, and mitigate performance issues that occur within the facility". Elsewhere, it notes that "identification of possible performance issues should be initiated by either the IBR facility owner/operator (i.e., the GO/GOP) or by the transmission entities with a wide-area view (i.e., the TOP, RC, or BA). However, the onus of analysis and development of mitigating actions should be on the asset owner to eliminate the possible risk of repeated abnormal performance issues". It is suggested that the scope clarify the distinction between performance issues within the plant and system performance issues. Presumably, responsibility to "identify, analyze, and mitigate performance issues" within the plant is with the GO/GOP, while responsibility for system performance analysis is with the TOP, RC or BA.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	Yes
Document Name	

Comment

HQT supports NPCC- RSC comments

Likes 0	
Dislikes 0	

Response

Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments

Answer	Yes
Document Name	

Comment

PG&E agrees with the proposed scope of the SAR.

PG&E agrees that a new Reliability Standard should be created that is specific to IBRs to avoid any confusion with the current devices covered by PRC-004. PRC-004 addresses Misoperations caused by "Protection Systems" components (a NERC Glossary term). Inverters/controllers are not defined as Protection Systems components which indicates a new Standard should be created to address the performance requirements for IBRs. A new Standard will also allow it to fit within the current work NERC has started to address the potential new registration type for Distributed Energy Resources (DER) using Inverter-Based Resources (IBR).

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 SAR scope. Additionally, EEI agrees with the IRPS that a new Reliability Standard that specifically address IBR performance is needed.	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
Hydro One has not identified any objections to NERC creating a NEW standard to address the issues related to IBRs, but we would oppose to changing existing PRC-004 as the scope of proposed work for IBR does not align with existing PRC-004.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
In light of recent IBR events, including the two Odessa events, Texas RE appreciates and supports this project to analyze and mitigate unexpected or unwarranted protection and control operations from inverter-based resources. Texas RE seeks clarification on the following statement: "the SAR is proposing that the BA and RC have the ability and authority to voluntarily initiate analysis of the abnormal performance issues by the asset owner (i.e., the GO)". Texas RE understands this language to mean that the BA and RC can begin their independent analyses of system disturbances. Texas RE recommends, however, that the language is clear that the BA and RC have the authority to require analysis for issues they notice for which a GO has not yet initiated a review. Additionally, Texas RE recommends clarifying that legacy equipment refers to equipment that is no longer made or supported by the manufacturer.	
Likes 0	
Dislikes 0	

Response	
Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	Yes
Document Name	
Comment	
We agree with this effort but the SAR should specifically avoid modifying PRC-004 for all the reasons the SAR stated it recommends a new standard instead.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Ameren believes that the forensic analysis and post event setting adjustment may have to be done at the Planning level.	
Likes 0	
Dislikes 0	
Response	
Rajesh Geevarghese - Exelon - 1,3 - RF	
Answer	Yes
Document Name	
Comment	
Exelon supports the EEI comments.	
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 SAR proposes requirements for analysis and mitigation of IBR performance issues following a disturbance. Such requirements may be useful when assessing events for root causes. The SAR makes an important distinction between control system and Protection System operations. Southern believes a new standard to solely address control system evaluation would be helpful. Also, we believe that the existing PRC-004 standard adequately addresses the Protection System operation evaluation and possible corrective actions for events involving the tripping of generation. The proposed SAR holds that the BA or RC should have certain authorities to identify and address abnormal performance issues. In this regard, Southern believes the SAR should recognize existing authorities granted by the TOP-003 and IRO-010 standards. Also, because NERC and industry are under increasing pressure to prioritize resources, standards developed within this SAR should address the BA, TOP, and RC's role in determining what disturbances are significant and justifiably warrant analysis. The standard drafting team should use its discretion when considering how to address the unique challenges of legacy equipment including whether their performance is expected or otherwise considered normal behavior under certain conditions and because of technical limitations.	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
RF supports this project and prefers the SDT to create a new standard to address analysis and mitigation of undesired performance by inverter-based resources during grid faults. The SAR includes the language "*Rather than complicate the existing PRC-004 focused on Protection Systems, IRPS believes that a new standard should be developed specific to IBRs to ensure that any unexpected ceasing of current injection (partial or full) is analyzed by the applicable Generator Owner and mitigated to the extent possible.*" RF concurs with this statement.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
Rather than modifying PRC-004, BPA agrees with the IRPS recommendation that a new NERC Reliability Standard be developed specific to Inverter-based Resources.	
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	Yes
Document Name	
Comment	
We agree with the proposed scope as dscribed in the SAR.	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
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	
James Baldwin - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brian Lindsey - Entergy - 1,3,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
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	
Michael Goggin - Grid Strategies, consultant to SEIA and ACP - 6 - NA - Not Applicable	
Answer	
Document Name	2023-02_Performance_of_IBRs_SAR, Goggin.docx
Comment	
While the proposed scope is generally reasonable and I do not want to delay this important work, I offer the attached redline edits and comments on the proposed scope.	
Likes 0	
Dislikes 0	
Response	

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

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

ERCOT joins the comments submitted by the SRC.

In addition, if the identification of the monitoring data referenced in the SRC comments is performed in this project, ERCOT believes the resulting Standard should require a level of detail similar to or better than the level of detail required by PRC-006. The data resolution and duration must also be sufficient to support the necessary analysis. For example, fault recording data should extend 1 – 5 seconds after the fault clears and should record multiple samples per cycle to capture dynamic response. This high resolution is necessary to identify failure modes like instantaneous frequency, voltage, or current trips. As another example, the fault recording triggers should be aligned with triggers for FRT/VRT modes so that smaller disturbances that cause performance failures will still be captured.

DDRs should all have continuous recording capabilities similar to phasor measurement units (PMUs) to provide consistency and the ability to capture data on longer duration issues (e.g., active power recovery ramp rate limitations). PMU data and other monitoring data should be stored long enough to allow event identification and data retrieval to occur before the data is overwritten or deleted (e.g., a 10-30 calendar days retention requirement). Having consistent and specific data will aid in event analysis, ensure data availability and accuracy, and enable the calculation of other parameters such as negative sequence current. Because the Point of Interconnection (POI) system frequency and voltage may differ from what is observed at the unit terminals, inverter level oscillography may also be needed to identify individual inverter level issues that may not be observable at the POI.

Likes 0	
Dislikes 0	
Response	

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	
Document Name	
Comment	

Leverage the existing PRC-004 standard to the greatest extent possible.

The existing PRC-004 does not currently contain many technology specific provisions that are limited to synchronous machine resources. If PRC-004 is modified to include IBR-specific provisions, there are terms that could use clarification such as BES interrupting device, and Composite Protection System, along with others that may need to be modified to account for how newer IBR protection systems are designed. In addition, although the conditions triggering the need for analysis may be different, the analysis and process to develop and implement the Corrective Action Plan would be the same. Therefore, we recommend the drafting team proceed first with modifying the existing PRC-004 standard and assess whether IBR specifc provisions can be accommodated.

Unlike when PRC-023 was revised to account for momentary cessation of IBR protection sytems, here the SDT is likely to encounter limited “overlap” of monitoring of protection systems that could cause confusion between synchronous and IBR protections. The SRC is aware that there are IBR specific actions that can cause actions and misoperations of IBR protection devices that do not apply to protection systems for synchronous generation resources. Unless the reporting requirements become confusing between the two technologies, a single standard for Misoperation Identification and Correction is preferable for the following reasons:

(1) It will likely expedite the time needed to develop the necessary requirements as opposed to starting from scratch. Considering that we are addressing a high risk reliability issue, the amount of time needed to develop a standard is an important consideration.

(2) It will avoid the need for a future standards development project to consolidate the two back into one. Case in point, industry requests to consolidate data specification standards, IRO-010 and TOP-003, into a single standard.

Legacy issues should be taken into consideration; however, not limit facilities ability to operate in a reliable manner.

The SRC supports the language on page 3 of the SAR:

“Considerations may be needed for legacy facilities, but the root cause analysis of the abnormal performance and determination of any mitigating measures should be conducted.”

However, the SAR should require the SDT to identify the level of reliability impact when legacy facilities need to be mitigated. To the extent, the root cause of multiple events can be shown to be tied to legacy design, consideration should be given to at what point might modifications or changes to protection and control equipment become necessary for continued operation, particularly if not aligned with interconnection requirements as detailed in the SAR on page 4.

“IRPS would also like to point out that the NERC reports have highlighted that the protection/controls that “operate as they are programmed” does not necessarily mean correct operation as per interconnection requirements. When a plant trips off-line for an external fault for reasons that are not expected (or allowed per interconnection requirements) nor are likely modeled appropriately in planning assessments, these types of abnormal reductions (tripping, controls, or controller interactions) should be analyzed and mitigated by the GO/GOP in a timely manner.”

Coordinate the work of IBR Drafting Teams to ensure alignment and compatibility and minimize duplication.

On page 5, there is a question: ***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)?****”*

The response is currently listed as: *“N/A.”*

The SRC requests the SAR be revised to reflect that there are at least two existing projects which are associated with misoperations of protection systems:

{C}o   {C}Project 2023-01 EOP-004 IBR Event Reporting

{C}o   {C}Project 2021-04 Modifications to PRC-002 - Phase II (i.e. disturbance monitoring data for IBRs)

In order to ensure the success of all three projects in an expeditous manner, and to make efficient use of SME resources, the SRC recommends that these three project teams work closely in coordination with each other. This includes coordinating IBR-related requirements among the three projects to avoid gaps and overlaps among the affected Reliability Standards, along with coordination of the schedules for posting the Standards for comments and balloting.

We strongly support the following text from the SAR (page 2):

"To be clear, the SAR is not proposing that the BA or RC is responsible for identifying these events; rather, the SAR is proposing that the BA and RC have the ability and authority to voluntarily initiate analysis of the abnormal performance issues by the asset owner (i.e., the GO). It is important that the GO is accountable for analyzing these events, has necessary monitoring equipment installed, and cooperates with the BA/RC by providing operational data and analytical results."

The EOP-004 Event Reporting requirements should be limited to information that RCs and BAs have immediate to access to. Therefore PRC-004 should require more specific data from GOs and TOs which are not readily available to RCs and BAs for analysis. While this project is focused on the need to investigate and analyze events in which IBRs perform abnormally, effectively coordinating these three projects requires clear identification of the monitoring data needed to perform the requisite event analysis. The needed monitoring data has not been clearly identified thus far, and this SAR scope should be amended to require clear identification of the necessary data.

In addition, the work of PRC-002 Phase II project, although well ahead of Project 2023-01 and 2023-02 may need to be paused until it is clear the proposed IBR data requirements are sufficient for IBR Event analysis requirements and protection system misoperations requirements. The data needed for fulfilling requirements to meet the reliability objectives of PRC-004 must be complemented by the requirements specified in PRC-002. In lieu of a pause, the PRC-002 Phase II team should consult with the other two teams to ensure the proposed PRC-002 revisions are sufficiently comprehensive. Determining whether to pause the PRC-002 Phase II project and coordinating the PRC-002 revisions with the revisions proposed by the other two projects should also account for the implementation plan timeframes needed to ensure that affected entities have adequate lead time to procure and install the necessary monitoring equipment.

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - PJM Interconnection, L.L.C. - 2 - RF

Answer	
Document Name	

Comment

PJM supports the ISO/RTO Council Standards Review Committee (IRC SRC) comments and is providing the following additional comments:

- PJM requests the need for "PMU-like" data recorded and stored when an IBR trips so that appropriate root cause can occur. Requiring this data to be made available will allow coordination between event data captured, event analyses, and lead to post-event protection setting adjustments, if required. Requiring recorded data to be made available for MOD-033 assessments could also be very helpful in identifying and preventing system events and improve modeling data. And any changes to settings that impact the dynamic response also need to be coordinated with MOD-026/027.
- PJM requests the use of criteria as defined in PRC-024-3. That is, if a unit ceases output within the no-trip zones, it can be considered a misoperation.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	

Lindsey Mannion - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	
RF appreciates the efforts of the IRPS and supports a project to create a new standard to address analysis and mitigation of undesired performance by inverter-based resources during grid faults. Additionally, it appears this SAR intends Project 2023-02 to work within the existing BES definition and registration criteria. However, coordination may be required between any Project 2023-02 Standard Drafting Team and the Electric Reliability Organization's efforts in response to FERC's Order under Docket RD22-4-000, which directed NERC to develop a work plan to identify and register owners and operators of IBRs connected to the BPS that are not currently included in the BES definition but have an aggregate, material impact on the reliability operation of the BPS.	
Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5,6	
Answer	
Document Name	
Comment	
Constellation further suggests that the data the SAR is looking to obtain is of less value to improving the reliability of the BES than that proposed in the modification of PRC-002 underway.	

Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	
Document Name	
Comment	

SPP RTO recommends that the **Project 2023-02** Standard Drafting Team (SDT) takes into consideration working with the **Project 2020-02 Modifications to PRC-024** SDT to ensure that the appropriate performance standard can be structured to address IBR ride-through as well as provide service during a system disturbance. From our perspective, the future **Project 2023-02** SDT will not be able to accomplish their goals without the **coordination of the PRC-024** SDT. For clarity, NERC has already identified that PRC-024-3 doesn't address the needs pertaining to IBR ride-through during a system disturbance as well as provide quality service. At this point, NERC feels that they need to develop a quality performance-based standard to address those concerns. Moreover, it doesn't seem efficient nor logical to start work on this type of project when the ride-through concerns haven't been addressed. However, if the **Project 2023-02** SDT determines that there is a need to move forward with this project, this coordination will would be highly recommend to help ensure success for this project.

Furthermore, we noticed that the SAR mentioned the inclusion of Battery Storage (ESRs). We recommend that the **Project 2023-02** SDT takes into consideration of working with the System Planning Impacts from DER Working Group (SPIDERWG-Project 2022-02 MOD-032-1) to ensure that Distributed Energy Resources (DERs) are included in their efforts. In our opinion, this coordination will help ensure all IBR, DER and ESR ride-through issues are addressed at one time instead of continuously reopening standards to address various resources on an individual basis.

From our perspective, this project can't be a success until appropriate data collection issues are addressed in reference to IBRs, DERs and ESRs. Also, the data collection efforts will contribute to appropriate model builds to ensure appropriate analysis of the grid. In addition, the model build efforts will help in the efficiency of developing a quality performance standard to address ride-through concerns applicable to the various generation resources (IBRs, DERs and ESRs).

Finally, we recommend that **Project 2023-02** SDT takes into consideration if any revisions or new definition changes made to the Glossary of Terms should be made applicable to the Rules of Procedure (RoP) as well. This effort would ensure that both documents are properly aligned when it comes to definitions. For the record, **Project 2015-04 Alignment of Terms** addresses these type efforts.

Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1,3,6	
Answer	
Document Name	
Comment	

No comment	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	
Document Name	
Comment	
Constellation further suggests that the data the SAR is looking to obtain is of less value to improving the reliability of the BES than that proposed in the modification of PRC-002 underway. Kimberly Turco on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	
Document Name	
Comment	

N/A	
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	

While PG&E supports the intent of the SAR and the proposed changes, PG&E recommends caution when discussing the BA and RC involvement in Misoperation analysis. The explanation and justification for the SAR indicate that "…the BA or RC have the authority to identify abnormal performance issues which should then initiate analysis and mitigations by the GO". If not carefully defined, provisions in the proposed Reliability Standard(s) could create excessive work for the participating GOs, introducing convoluted work cycles, impose unreasonable time constraints on event analysis and cause confusion about share responsibilities.

PG&E recommends complete authority and responsibility to identify and perform analyses should remain with the GO, unless a large-area Disturbance or significant event occurs.

Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	

- We propose a separate standard for IBRs given that IBRs have different technologies. Proposed requirements may need to be articulated specifically to take into account these new technologies. A separate standard will also raise more awareness amongst IBR owners.
- Given that there are at least two current projects which are associated with misoperations of protection systems (Project 2023-01 EOP-004 for IBR Event Reporting and 2021-04 for PRC-002 Phase II Disturbance monitoring data for IBRs), we recommend that these three projects work closely in coordination.

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:

a) General Comments:

i. The NAGF supports the NERC IRPS recommendation that a new standard be developed that requires analysis and mitigation (to the extent possible) of unexpected or unwarranted control operations from BES inverter-based resources.

ii. The NAGF recommends that the references to "protection and control operations" be revised to state "control system performance" throughout the draft SAR document.

iii. The NAGF agrees that legacy IBR equipment may not be able to mitigate certain performance issues. Once this is confirmed and communicated, there should be no need to perform repeat root cause analysis and identification of possible mitigations for such IBR facilities. Requiring GOs to do such does not provide value and is not an effective/efficient use of GO resources.

iv. The NAGF recommends that the SAR drafting team review existing active NERC Projects such as Projects 2020-02 and 2023-01 to ensure there is no overlap with Project 2023-02.

v. The NAGF recommends that the draft SAR include provisions for a Phase 2 to address reporting of newly registered IBR assets in response to the FERC Order E-1-RD22-4000: Registration of Inverter-Based Resources.

b. Industry Need Section:

i. The NAGF believes that the statement "NERC has also highlighted that many Generator Owners are not aware of these trips" is misleading, is of no value, and does not belong in the draft SAR. The use of the term "trip" is not appropriate to describe an IBR current injection cessation event. Furthermore, due to the speed of IBR electronic controls (milli seconds or less), appropriate data recording equipment would need to be in place to record such events. If such equipment is not in place, GOs would not be aware of current cessation events unless they were long-duration events.

ii. The NAGF agrees that the BA or RC should play a part in defining/determining what disturbances are significant and justifiably warrant an analysis. A GO defined criterion may result in analysis of very insignificant events. In addition, recommend that the draft SAR tie in with Project 2023-01 (EOP-004) to ensure consistency with disturbances requiring analysis.

c. Purpose and Goal Section:

i. Page 2, second paragraph, second sentence – the NAGF requests clarification regarding the statement "…result in widespread reduction of power output…". Is this a reduction on both real and reactive power?

d. Detailed Description Section:

i. Page 3, second paragraph, second sentence – recommend removing " The past few NERC disturbance reports have highlighted limited awareness and understanding by facility owners that abnormal performance has even occurred and therefore" for the reasons described in b.i. above.

ii. Page 4, first paragraph – recommend removing language after “IRPS believes that all BES IBR generation facilities should be applicable to this standard”. Remaning language is not in scope for this project.

iii. Page 4, second paragraph, first sentence – the NAGF notes that the draft language “for any reason” is too broad and conflicts with other sections of the draft SAR that specifically identify the event types to be addressed.

e. Cost Impact Assessment Section:

i. The NAGF notes that the costs of adding additional monitoring equipment, engineering/analytical capabilities, and coordination with equipment manufacturers is significant and not adequately addressed in this section. NAGF members have provided the following information:

$50K for monitoring equipment to be installed per inverter. For a 160MW solar facility, there are approximately 64 inverters. $50K X 64 = $3.2 M.

ii. The NAGF recommends that the second sentence starting with “This type of activity…” be removed as it does not provide value for describing the potential cost impacts.

Likes 0	
Dislikes 0	

Response

Wesley Yeomans - New York State Reliability Council - 10

Answer	
Document Name	

Comment

The requirement in the SAR is written in such a way that an unreliable event first takes place prior to any action on the part of the GO/GOP. It is suggested that the GO/GOP should be required to analize its IBR and reach out to inverter and plant controller manufactures to determine and attest to its ride-through charactoristics before a disturbance occurs.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

Duke Energy suggests:

1. The development of a new NERC Reliability Standard to specifically address IBR issues. In addition to IBRs, Duke Energy would encourage other renewable resources be part of the SAR or an additional SAR proposed for other sources (e.g. synchronous condensers and wind generators).

2. Adding an IBR and related definition(s) to the new NERC Reliability Standard and NERC Glossary of Terms.

3. The new NERC Reliability Standard not be limited to BES definition component minimum threshold limits (e.g., connected at a voltage of 100 kV or above) for power producing resources.

4. Clarifying if the term “performance” is only related to tripping and misoperation or whether it means any type of general operational performance.

(Note: Some references in the SAR indicate ‘events’ and others ‘loss events’; a loss event is much more discernable and definable than the broad range of occurrences included by the general reference, ‘event’. The discussion in the Scope section seems to use this general type of ‘performance’, which could be difficult to define).

If both types of performance are included for trips and failures to meet expected performance, it may be worth considering separating these categories into two SARs. Trips seem to be the most critical at the moment (and may be the focus of this SAR) and tends to align philosophically with PRC-004 which uses terms like ‘misopeations’ and “interrupting device operation” rather than ‘performance.’

5. This SAR coordinate with the work contemplating changes to the 75 MVA reporting limit.

6. SAR proposes the BA and RC have a voluntary role in initiating analysis of abnormal performance. Duke Energy believes the the BA and RC role should be mandatory.

Likes 0	
Dislikes 0	

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy - DTE Electric

Answer	
Document Name	

Comment

Nothing futher at this time.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter

Answer	
Document Name	

Comment

FirstEnergy believes a new Reliability Standard that specifically addresses IBR performance would be the best approach.

Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	
Document Name	
Comment	
AZPS recommends that references to updating the existing PRC-004 (or other standards) be removed from the SAR.	
Likes 0	
Dislikes 0	
Response	

Standards Announcement

Project 2023-02 Performance of IBRs
Standard Authorization Request

Informal Comment Period Open through March 23, 2023

Now Available

A 30-day informal comment period for the **Project 2023-02 Performance of IBRs** Standard Authorization Request (SAR), is open through **8 p.m. Eastern, Thursday, March 23, 2023**.

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

For more information or assistance, contact Standards Developer, Dominique Love (via email) or at 404-217-7578. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2023-02 Performance of IBRs observer list" in the Description Box.

RELIABILITY CORPORATION

Atlanta, GA 30326
404-446-2560 | www.nerc.com

Consideration of Comments

Project Name: 2023-02 Performance of IBRs | SAR
Comment Period Start Date: 2/22/2023
Comment Period End Date: 3/23/2023
Associated Ballot(s):

There were 41 sets of responses, including comments from approximately 130 different people from approximately 91 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 SAR 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	1,3,5	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
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	MRO,SPP RE,WECC	SRC 2023	Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	1	WECC
					Helen Lainis	IESO	1	NPCC
					Matt Goldberg	ISONE	1	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Greg Campoli	NYISO	1	NPCC
					Elizabeth Davis	PJM	2	RF
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE

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
MRO	Jou Yang	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO

					Chris Bills	City of Independence, Power and Light Department	5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bryan Sherrow	Board of Public Utilities	1	MRO
					Terry Harbour	Berkshire Hathaway Energy - MidAmerican Energy Co.	1	MRO

					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shonda McCain	Omaha Public Power District	6	MRO
					George E Brown	Pattern Operators LP	5	MRO
					George Brown	Acciona Energy USA	5	MRO
					Jaimin Patel	Saskatchewan Power Cooperation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jay Sethi	Manitoba Hydro	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO

DTE Energy - Detroit Edison Company	Karie Barczak	3,5		DTE Energy - DTE Electric	Adrian Raducea	DTE Energy - Detroit Edison Company	5	RF
					Patricia Ireland	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
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
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	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

					Frank Lee	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
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
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
					Sheraz Majid	Hydro One Networks, Inc.	1	NPCC

Deidre Altobell	Con Edison	1	NPCC
Jeffrey Streifling	NB Power Corporation	1	NPCC
Michele Tondalo	United Illuminating Co.	1	NPCC
Chantal Mazza	Hydro Quebec	1	NPCC
Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
Quintin Lee	Eversource Energy	1	NPCC
Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
Dan Kopin	Vermont Electric Power Company	1	NPCC
James Grant	NYISO	2	NPCC
John Pearson	ISO New England, Inc.	2	NPCC
Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC
Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC

Randy MacDonald	New Brunswick Power Corporation	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

					Glen Smith	Entergy Services	4	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
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Bryan Wood	Southwest Power Pool Inc	2	MRO

					Brian Strickland	Southwest Power Pool Inc	2	MRO
					Derek Hawkins	Southwest Power Pool Inc.	2	MRO
					Margaret Quispe	Southwest Power Pool Inc.	2	MRO
					Mia Wilson	Southwest Power Pool Inc.	2	MRO

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.

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The MRO NSRF provides the following comments:

1. Need to eliminate references to trip, tripping, and Protection System in this SAR – those parts of IBRs are already covered sufficiently (included and subject to the standard) by the existing PRC-004.

2. A new standard is definitely better to address the control system performance evaluation.

3. The BA, TOP, and RC should play a part in determining what disturbances are significant and justifiably warrant analysis. Further, an analysis and report by the GO/GOP to the BA, TOP, and RC can be specified in the existing TOP-003 and IRO-010 standards, rendering that part of the SAR unneeded. Those standards give authority already. A GO alone developed criterion may result in analysis of very insignificant (single facility) events.

4.Thoughts on legacy equipment:

Some recognition of the limitations of existing equipment needs to be addressed in the proposed scope to eliminate all performance issues through mitigation plans. This could be done by adding “where possible” to the phrase “…identify, analyze, and mitigate performance issues where possible.

Use of unwarranted – there are times where the performance (cease conduction) is very much warranted – some at NERC do not seem to understand this – (e.g., loss of synchronizing signal – no alternate control modes – processor speed limitations – control algorithm limitations) The repeated characterization all inverter performance behavior as “unexpected”, “abnormal”, “unwarranted”, “anomalous” does not correctly represent the behavior of controls that were neither designed nor built to be able to ride-thru the system disturbances to which they are being subjected. Through the repeated evaluation of events and multiple control parameter setting changes performed over the past five (5) years, the behavior observed is as expected, deemed normal, and completely warranted depending upon the legacy and capabilities of the particular inverter. A distinction between “operating as they are programmed” and “operating within the design characteristics of the control system” needs to be recognized and respected. Certain legacy equipment has constraints and cannot be made to be able to ride through all system disturbances. There is little value in this standard requiring repeated identification, analysis, and possible mitigation evaluation for plants that have adjusted all possible parametric options for the desensitization to system conditions and for the fastest possible recovery time. 5. “Abnormal performance” must be defined both in the SAR and then officially in the Glossary of Terms Used in NERC Reliability Standards. Without a definition the SAR and subsequent draft standard will fail to achieve the need of the project. The MRO suggests the SAR drafting team develop a list of ‘abnormal performance’ issues, which will focus the scope of the SAR and provide a starting point for the Standards Drafting Team.

Likes 0	
Dislikes 0	

Response
1. The team will consider the areas of the existing PRC-004 and be cognizant of potential overlap. 2. The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both. 3. The team has representatives that fit in all four registration categories. The team will be considering all members’ point of view. The team will consider the tradeoffs related to the size of events for analysis.

4. The team acknowledges the concepts outlined in the response as ones that deserve consideration and deliberation. The team will contemplate all components to this comment during the drafting process. The SAR project scope includes this consideration with the language, "Considerations may be needed for legacy facilities, but the root cause analysis of the abnormal performance and determination of any mitigating measures should be conducted." 5. The SAR scope already appropriately considers "the possibility of adding new or modifying existing NERC Glossary Terms, as the drafting team determines necessary, to ensure clarity in the standard.	
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 scope and submits the following comments for consideration: a) The NAGF notes that the existing Reliability Standard PRC-004-06: Protection System Misoperation Identification and Correction already addresses BES IBR protection systems/components. Therefore, the NAGF recommends to remove references to "protections" in the Project Scope section. b) The NAGF recommends the first sentence of the Project Scope section be modified as follows: "...and unreliable manner to identify, analyze, and mitigate performance issues *to the extent possible* that occur within the facility." c) All BES IBR battery energy storage resources, whether they as considered generator or transmission resources, should be applicable to this standard. Therefore, the NAGF recommends removing or amending the sentence regarding battery energy storage resources.	
Likes 0	
Dislikes 0	

Response	
a. The intent of the SAR is to analyze and mitigate unexpected or unwarranted protection and control operations from inverter-based resources following the identification of such a performance issue. The team will consider the areas of the existing PRC-004 and be cognizant of potential overlap. b. The team believes that all IBR performance issues must be identified, analyzed, and mitigated. Regarding legacy facilities, the SAR project scope includes this consideration with the language, "Considerations may be needed for legacy facilities, but the root cause analysis of the abnormal performance and determination of any mitigating measures should be conducted." c. The team agrees with this comment and has made changes in the SAR to reflect these changes.	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	No
Document Name	
Comment	
Tri-State mostly agrees with the SAR, however recommends that references to updating the existing PRC-004 (or other standards) be removed from the SAR. A new standard should be created for Inverter Based Resources.	
Likes 0	
Dislikes 0	
Response	
The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both.	
Kimberly Turco - Constellation - 5,6	
Answer	No
Document Name	
Comment	

Constellation Generation feels the creation of a new standard to address only IBR's is unnecessary and overly burdensome when existing standards could address IBR's and in many cases already do. The SAR mentions "current cessation" and other limited capabilities that could be addressed in existing standards such as PRC-019 and PRC-024, rather than creation of a new and duplicative standard. Kimberly Turco on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both.	
Alison MacKellar - Constellation - 5,6	
Answer	No
Document Name	
Comment	
Constellation Generation feels the creation of a new standard to address only IBR's is unnecessary and overly burdensome when existing standards could address IBR's and in many cases already do. The SAR mentions "current cessation" and other limited capabilities that could be addressed in existing standards such as PRC-019 and PRC-024, rather than creation of a new and duplicative standard. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	

Response	
The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both.	
Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the MRO NSRFs comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to MRO NSRFs' comment.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	No
Document Name	
Comment	
The ISO/RTO Council (IRC) Standards Review Committee (SRC) agrees with the general scope of the project, but has recommendations to help ensure these requirements are effective and non-duplicative with other IBR projects currently underway. Our response to Question 2 provides recommendations.	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment, the team agrees and will be coordinating with the other active IBR drafting teams.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council Standards Review Committee (SRC).	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment please review ISO/RTO Council SRC.	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Tacoma Power has no comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF	

Answer	Yes
Document Name	
Comment	
Response Created in error- please delete	
Likes 0	
Dislikes 0	
Response	
The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both. The team has representatives that fit in all four registration categories. The team will be considering all members point of view. The SAR project scope includes this consideration with the language, "Considerations may be needed for legacy facilities, but the root cause analysis of the abnormal performance and determination of any mitigating measures should be conducted."	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
AZPS supports the proposed SAR and agrees with the IRPS that a new Reliability Standard should be developed to specifically address IBR performance.	
Likes 0	
Dislikes 0	
Response	

The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both.	
Nazra Gladu - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Currently, Manitoba Hydro does not have any IBRs, but likley will in the future.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
BC Hydro agrees with IRPS that a new Reliability Standard specific to IBRs performance should be developed.	
Likes 0	
Dislikes 0	
Response	
The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	

Answer	Yes
Document Name	
Comment	
FirstEnergy agrees with the scope of the SAR.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Lori Frisk - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power supports EEI’s comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to EEI's comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	

None.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment	
Thomas Foltz - AEP - 3,5,6	
Answer	Yes
Document Name	
Comment	
AEP agrees with the perceived reliability need expressed in this SAR and agree with the authors that it would be inadvisable to revise PRC-004, as among other reasons, the scope of PRC-004 would need to be expanded to cover ride-through issues that may not be classifiable as protection misoperation. We also agree that an entirely new standard would be the preferred means to meet the objectives of the SAR. In addition, we suggest that consideration also be given to perhaps sharing this SAR with the Project 2020-02 drafting team for it to possibly augment their efforts rather than having the “Analysis and Mitigation of BES Inverter-Based Resource Performance Issues” SAR have its own distinct project (2023-02). If a new standard were to be written under 2023-02, it could end up a parallel effort to Project 2020-02 (PRC-024) which is now under revision by a project that specifically aims to convert it from a relay setting standard into a true ride-through standard. Identification, analysis, and mitigation of abnormal, unexpected, and unwarranted IBR behaviors affecting ride-through performance, which is what this SAR proposes to require, are actions that would necessarily be subsumed into any ride-through requirements. In any event, care needs to be taken to ensure that no efforts are duplicative across projects and/or standards.	
Likes 0	
Dislikes 0	
Response	

The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both. The team agrees with the recommendation to coordinate with PRC-024 (project 2020-02).	
Wesley Yeomans - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
The Scope requires IBRs to "identify, analyze, and mitigate performance issues that occur within the facility". Elsewhere, it notes that "identification of possible performance issues should be initiated by either the IBR facility owner/operator (i.e., the GO/GOP) or by the transmission entities with a wide-area view (i.e., the TOP, RC, or BA). However, the onus of analysis and development of mitigating actions should be on the asset owner to eliminate the possible risk of repeated abnormal performance issues". It is suggested that the scope clarify the distinction between performance issues within the plant and system performance issues. Presumably, responsibility to "identify, analyze, and mitigate performance issues" within the plant is with the GO/GOP, while responsibility for system performance analysis is with the TOP, RC or BA.	
Likes 0	
Dislikes 0	
Response	
The team believes the SAR already appropriately allows for the consideration outlined in the comment by stating, "This includes any types of protections or controls that result in abnormal performance issues within the plant, including abnormal performance resulting in anomalous behavior of active power output from the facility during events."	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	

Comment	
HQT supports NPCC- RSC comments	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see responses to these two comments.	
Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E agrees with the proposed scope of the SAR. PG&E agrees that a new Reliability Standard should be created that is specific to IBRs to avoid any confusion with the current devices covered by PRC-004. PRC-004 addresses Misoperations caused by "Protection Systems" components (a NERC Glossary term). Inverters/controllers are not defined as Protection Systems components which indicates a new Standard should be created to address the performance requirements for IBRs. A new Standard will also allow it to fit within the current work NERC has started to address the potential new registration type for Distributed Energy Resources (DER) using Inverter-Based Resources (IBR).	
Likes 0	
Dislikes 0	
Response	

The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed SAR scope. Additionally, EEI agrees with the IRPS that a new Reliability Standard that specifically address IBR performance is needed.	
Likes 0	
Dislikes 0	
Response	
The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
Hydro One has not identified any objections to NERC creating a NEW standard to address the issues related to IBRs, but we would oppose to changing existing PRC-004 as the scope of proposed work for IBR does not align with existing PRC-004.	
Likes 0	
Dislikes 0	

Response	
The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
In light of recent IBR events, including the two Odessa events, Texas RE appreciates and supports this project to analyze and mitigate unexpected or unwarranted protection and control operations from inverter-based resources. Texas RE seeks clarification on the following statement: "the SAR is proposing that the BA and RC have the ability and authority to voluntarily initiate analysis of the abnormal performance issues by the asset owner (i.e., the GO)". Texas RE understands this language to mean that the BA and RC can begin their independent analyses of system disturbances. Texas RE recommends, however, that the language is clear that the BA and RC have the authority to require analysis for issues they notice for which a GO has not yet initiated a review. Additionally, Texas RE recommends clarifying that legacy equipment refers to equipment that is no longer made or supported by the manufacturer.	
Likes 0	
Dislikes 0	
Response	
The SAR already appropriately considers the clarifying language "Therefore, it is important that the BA or RC have the authority to identify abnormal performance issues which should then initiate analysis and mitigations by the GO. To be clear, the SAR is not proposing that the BA or RC is responsible for identifying these events; rather, the SAR is proposing that the BA and RC have the ability and authority to voluntarily initiate analysis of the abnormal performance issues by	

the asset owner (i.e., the GO). It is important that the GO is accountable for analyzing these events, has necessary monitoring equipment installed, and cooperates with the BA/RC by providing operational data and analytical results." To the legacy comment, the SAR project scope includes this consideration with the language, "Considerations may be needed for legacy facilities, but the root cause analysis of the abnormal performance and determination of any mitigating measures should be conducted." Further, the SAR already appropriately considers "the possibility of adding new or modifying existing NERC Glossary Terms, as the drafting team determines necessary, to ensure clarity in the standard."	
Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	Yes
Document Name	
Comment	
We agree with this effort but the SAR should specifically avoid modifying PRC-004 for all the reasons the SAR stated it recommends a new standard instead.	
Likes 0	
Dislikes 0	
Response	
The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both.	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	

Ameren believes that the forensic analysis and post event setting adjustment may have to be done at the Planning level.	
Likes 0	
Dislikes 0	
Response	
From the commentary, the team believes that any setting adjustment needs to be coordinated with both the planning model and operating model.	
Rajesh Geevarghese - Exelon - 1,3 - RF	
Answer	Yes
Document Name	
Comment	
Exelon supports the EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to EEI's comment.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

The SAR proposes requirements for analysis and mitigation of IBR performance issues following a disturbance. Such requirements may be useful when assessing events for root causes. The SAR makes an important distinction between control system and Protection System operations. Southern believes a new standard to solely address control system evaluation would be helpful. Also, we believe that the existing PRC-004 standard adequately addresses the Protection System operation evaluation and possible corrective actions for events involving the tripping of generation. The proposed SAR holds that the BA or RC should have certain authorities to identify and address abnormal performance issues. In this regard, Southern believes the SAR should recognize existing authorities granted by the TOP-003 and IRO-010 standards. Also, because NERC and industry are under increasing pressure to prioritize resources, standards developed within this SAR should address the BA, TOP, and RC's role in determining what disturbances are significant and justifiably warrant analysis. The standard drafting team should use its discretion when considering how to address the unique challenges of legacy equipment including whether their performance is expected or otherwise considered normal behavior under certain conditions and because of technical limitations.	
Likes 0	
Dislikes 0	
Response	
The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both. The team has representatives that fit in all four registration categories. The team will be considering all members point of view. The SAR project scope includes this consideration with the language, "Considerations may be needed for legacy facilities, but the root cause analysis of the abnormal performance and determination of any mitigating measures should be conducted."	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	

Comment	
RF supports this project and prefers the SDT to create a new standard to address analysis and mitigation of undesired performance by inverter-based resources during grid faults. The SAR includes the language "*Rather than complicate the existing PRC-004 focused on Protection Systems, IRPS believes that a new standard should be developed specific to IBRs to ensure that any unexpected ceasing of current injection (partial or full) is analyzed by the applicable Generator Owner and mitigated to the extent possible.*" RF concurs with this statement.	
Likes 0	
Dislikes 0	
Response	
The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Rather than modifying PRC-004, BPA agrees with the IRPS recommendation that a new NERC Reliability Standard be developed specific to Inverter-based Resources.	
Likes 0	
Dislikes 0	
Response	

The team believe that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
We agree with the proposed scope as dscribed in the SAR.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy - DTE Electric	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for the support.	
James Baldwin - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Brian Lindsey - Entergy - 1,3,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Teresa Krabe - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Goggin - Grid Strategies, consultant to SEIA and ACP - 6 - NA - Not Applicable	
Answer	
Document Name	2023-02_Performance_of_IBRs_SAR, Goggin.docx
Comment	
While the proposed scope is generally reasonable and I do not want to delay this important work, I offer the attached redline edits and comments on the proposed scope.	
Likes 0	
Dislikes 0	
Response	
Thank you for the support, the team has reviewed and taken the edits into consideration.	

2. Provide any additional comments for the SAR drafting team to consider, if desired.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT joins the comments submitted by the SRC. In addition, if the identification of the monitoring data referenced in the SRC comments is performed in this project, ERCOT believes the resulting Standard should require a level of detail similar to or better than the level of detail required by PRC-006. The data resolution and duration must also be sufficient to support the necessary analysis. For example, fault recording data should extend 1 – 5 seconds after the fault clears and should record multiple samples per cycle to capture dynamic response. This high resolution is necessary to identify failure modes like instantaneous frequency, voltage, or current trips. As another example, the fault recording triggers should be aligned with triggers for FRT/VRT modes so that smaller disturbances that cause performance failures will still be captured. DDRs should all have continuous recording capabilities similar to phasor measurement units (PMUs) to provide consistency and the ability to capture data on longer duration issues (e.g., active power recovery ramp rate limitations). PMU data and other monitoring data should be stored long enough to allow event identification and data retrieval to occur before the data is overwritten or deleted (e.g., a 10-30 calendar days retention requirement). Having consistent and specific data will aid in event analysis, ensure data availability and accuracy, and enable the calculation of other parameters such as negative sequence current. Because the Point of Interconnection (POI) system frequency and voltage may differ from what is observed at the unit terminals, inverter level oscillography may also be needed to identify individual inverter level issues that may not be observable at the POI.	
Likes 0	
Dislikes 0	
Response	

Thank you for the comments and these will be considered by the team during drafting of the standard. Additionally the team notes that it will coordinate as appropriate with other concurrent NERC drafting efforts including PRC-028 which addresses the comments raised here.

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	
Document Name	
Comment	

Leverage the existing PRC-004 standard to the greatest extent possible.

The existing PRC-004 does not currently contain many technology specific provisions that are limited to synchronous machine resources. If PRC-004 is modified to include IBR-specific provisions, there are terms that could use clarification such as BES interrupting device, and Composite Protection System, along with others that may need to be modified to account for how newer IBR protection systems are designed. In addition, although the conditions triggering the need for analysis may be different, the analysis and process to develop and implement the Corrective Action Plan would be the same. Therefore, we recommend the drafting team proceed first with modifying the existing PRC-004 standard and assess whether IBR specifc provisions can be accommodated.

Unlike when PRC-023 was revised to account for momentary cessation of IBR protection sytems, here the SDT is likely to encounter limited “overlap” of monitoring of protection systems that could cause confusion between synchronous and IBR protections. The SRC is aware that there are IBR specific actions that can cause actions and misoperations of IBR protection devices that do not apply to protection systems for synchronous generation resources. Unless the reporting requirements become confusing between the two technologies, a single standard for Misoperation Identification and Correction is preferable for the following reasons:

(1) It will likely expedite the time needed to develop the necessary requirements as opposed to starting from scratch. Considering that we are addressing a high risk reliability issue, the amount of time needed to develop a standard is an important consideration.

(2) It will avoid the need for a future standards development project to consolidate the two back into one. Case in point, industry requests to consolidate data specification standards, IRO-010 and TOP-003, into a single standard.

Legacy issues should be taken into consideration; however, not limit facilities ability to operate in a reliable manner.

The SRC supports the language on page 3 of the SAR:

"Considerations may be needed for legacy facilities, but the root cause analysis of the abnormal performance and determination of any mitigating measures should be conducted."

However, the SAR should require the SDT to identify the level of reliability impact when legacy facilities need to be mitigated. To the extent, the root cause of multiple events can be shown to be tied to legacy design, consideration should be given to at what point might modifications or changes to protection and control equipment become necessary for continued operation, particularly if not aligned with interconnection requirements as detailed in the SAR on page 4.

"IRPS would also like to point out that the NERC reports have highlighted that the protection/controls that "operate as they are programmed" does not necessarily mean correct operation as per interconnection requirements. When a plant trips off-line for an external fault for reasons that are not expected (or allowed per interconnection requirements) nor are likely modeled appropriately in planning assessments, these types of abnormal reductions (tripping, controls, or controller interactions) should be analyzed and mitigated by the GO/GOP in a timely manner."

Coordinate the work of IBR Drafting Teams to ensure alignment and compatibility and minimize duplication.

On page 5, there is a question: ***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)?***"

The response is currently listed as: *"N/A."*

The SRC requests the SAR be revised to reflect that there are at least two existing projects which are associated with misoperations of protection systems:

{C}o {C}Project 2023-01 EOP-004 IBR Event Reporting

{C}o {C}Project 2021-04 Modifications to PRC-002 - Phase II (i.e. disturbance monitoring data for IBRs)

In order to ensure the success of all three projects in an expeditous manner, and to make efficient use of SME resources, the SRC recommends that these three project teams work closely in coordination with each other. This includes coordinating IBR-related requirements among the three projects to avoid gaps and overlaps among the affected Reliability Standards, along with coordination of the schedules for posting the Standards for comments and balloting.

We strongly support the following text from the SAR (page 2):

“To be clear, the SAR is not proposing that the BA or RC is responsible for identifying these events; rather, the SAR is proposing that the BA and RC have the ability and authority to voluntarily initiate analysis of the abnormal performance issues by the asset owner (i.e., the GO). It is important that the GO is accountable for analyzing these events, has necessary monitoring equipment installed, and cooperates with the BA/RC by providing operational data and analytical results.”

The EOP-004 Event Reporting requirements should be limited to information that RCs and BAs have immediate to access to. Therefore PRC-004 should require more specific data from GOs and TOs which are not readily available to RCs and BAs for analysis. While this project is focused on the need to investigate and analyze events in which IBRs perform abnormally, effectively coordinating these three projects requires clear identification of the monitoring data needed to perform the requisite event analysis. The needed monitoring data has not been clearly identified thus far, and this SAR scope should be amended to require clear identification of the necessary data.

In addition, the work of PRC-002 Phase II project, although well ahead of Project 2023-01 and 2023-02 may need to be paused until it is clear the proposed IBR data requirements are sufficient for IBR Event analysis requirements and protection system misoperations requirements. The data needed for fulfilling requirements to meet the reliability objectives of PRC-004 must be complemented by the requirements specified in PRC-002. In lieu of a pause, the PRC-002 Phase II team should consult with the other two teams to ensure the proposed PRC-002 revisions are sufficiently comprehensive. Determining whether to pause the PRC-002 Phase II project and coordinating the PRC-002 revisions with the revisions proposed by the other two projects should also account for the implementation plan timeframes needed to ensure that affected entities have adequate lead time to procure and install the necessary monitoring equipment.	
Likes 0	
Dislikes 0	
Response	
The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both. The team agrees with the recommendation to coordinate with other active projects. The team acknowledges the concepts outlined in the response as ones that deserve consideration and deliberation. The team will contemplate all components to this comment during the drafting process. The SAR project scope includes this consideration with the language, "Considerations may be needed for legacy facilities, but the root cause analysis of the abnormal performance and determination of any mitigating measures should be conducted." The team agrees with adding the current project teams with potentially related scopes. We will amend the SAR to reflect those teams.	
Elizabeth Davis - PJM Interconnection, L.L.C. - 2 - RF	

Answer	
Document Name	
Comment	

PJM supports the ISO/RTO Council Standards Review Committee (IRC SRC) comments and is providing the following additional comments:

- PJM requests the need for "PMU-like" data recorded and stored when an IBR trips so that appropriate root cause can occur. Requiring this data to be made available will allow coordination between event data captured, event analyses, and lead to post-event protection setting adjustments, if required. Requiring recorded data to be made available for MOD-033 assessments could also be very helpful in identifying and preventing system events and improve modeling data. And any changes to settings that impact the dynamic response also need to be coordinated with MOD-026/027.
- PJM requests the use of criteria as defined in PRC-024-3. That is, if a unit ceases output within the no-trip zones, it can be considered a misoperation.

Likes 0	
Dislikes 0	
Response	

The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both.

The team agrees with the recommendation to coordinate with other active projects

Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group

Answer	
Document Name	
Comment	

No additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	
RF appreciates the efforts of the IRPS and supports a project to create a new standard to address analysis and mitigation of undesired performance by inverter-based resources during grid faults. Additionally, it appears this SAR intends Project 2023-02 to work within the existing BES definition and registration criteria. However, coordination may be required between any Project 2023-02 Standard Drafting Team and the Electric Reliability Organization's efforts in response to FERC's Order under Docket RD22-4-000, which directed NERC to develop a work plan to identify and register owners and operators of IBRs connected to the BPS that are not currently included in the BES definition but have an aggregate, material impact on the reliability operation of the BPS.	
Likes 0	
Dislikes 0	
Response	
The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both. The team agrees with the recommendation to evaluate active FERC order during the drafting process.	

Alison MacKellar - Constellation - 5,6	
Answer	
Document Name	
Comment	
Constellation further suggests that the data the SAR is looking to obtain is of less value to improving the reliability of the BES than that proposed in the modification of PRC-002 underway. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both. The team agrees with the recommendation to coordinate with PRC-002/ PRC-028 (project 2021-04).	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	
Document Name	
Comment	
SPP RTO recommends that the **Project 2023-02** Standard Drafting Team (SDT) takes into consideration working with the **Project 2020-02 Modifications to PRC-024** SDT to ensure that the appropriate performance standard can be structured to address IBR ride-through as well as provide service during a system disturbance. From our perspective, the future **Project 2023-02** SDT will not be able to accomplish their goals without the **coordination of the PRC-024** SDT. For clarity, NERC has already identified that PRC-024-3 doesn't address the needs pertaining to IBR ride-through during a system disturbance as well as provide quality service. At this point, NERC feels that they need to develop a quality	

performance-based standard to address those concerns. Moreover, it doesn't seem efficient nor logical to start work on this type of project when the ride-through concerns haven't been addressed. However, if the **Project 2023-02** SDT determines that there is a need to move forward with this project, this coordination will would be highly recommend to help ensure success for this project. Furthermore, we noticed that the SAR mentioned the inclusion of Battery Storage (ESRs). We recommend that the **Project 2023-02** SDT takes into consideration of working with the System Planning Impacts from DER Working Group (SPIDERWG-Project 2022-02 MOD-032-1) to ensure that Distributed Energy Resources (DERs) are included in their efforts. In our opinion, this coordination will help ensure all IBR, DER and ESR ride-through issues are addressed at one time instead of continuously reopening standards to address various resources on an individual basis. From our perspective, this project can't be a success until appropriate data collection issues are addressed in reference to IBRs, DERs and ESRs. Also, the data collection efforts will contribute to appropriate model builds to ensure appropriate analysis of the grid. In addition, the model build efforts will help in the efficiency of developing a quality performance standard to address ride-through concerns applicable to the various generation resources (IBRs, DERs and ESRs). Finally, we recommend that **Project 2023-02** SDT takes into consideration if any revisions or new definition changes made to the Glossary of Terms should be made applicable to the Rules of Procedure (RoP) as well. This effort would ensure that both documents are properly aligned when it comes to definitions. For the record, **Project 2015-04 Alignment of Terms** addresses these type efforts.	
Likes 0	
Dislikes 0	
Response	
The team agrees with the comments and will coordinate with all concurrent and relevant NERC drafting teams including the team working on Project 2020-02, Modifications to PRC-024 to the extent required.	
Brian Lindsey - Entergy - 1,3,6	
Answer	
Document Name	

Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Kimberly Turco - Constellation - 5,6	
Answer	
Document Name	
Comment	

Constellation further suggests that the data the SAR is looking to obtain is of less value to improving the reliability of the BES than that proposed in the modification of PRC-002 underway. Kimberly Turco on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
The team believes this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both. The team agrees with the recommendation to coordinate with other active projects.	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments	
Answer	
Document Name	

Comment	
While PG&E supports the intent of the SAR and the proposed changes, PG&E recommends caution when discussing the BA and RC involvement in Misoperation analysis. The explanation and justification for the SAR indicate that "…the BA or RC have the authority to identify abnormal performance issues which should then initiate analysis and mitigations by the GO". If not carefully defined, provisions in the proposed Reliability Standard(s) could create excessive work for the participating GOs, introducing convoluted work cycles, impose unreasonable time constraints on event analysis and cause confusion about share responsibilities. PG&E recommends complete authority and responsibility to identify and perform analyses should remain with the GO, unless a large-area Disturbance or significant event occurs.	
Likes 0	
Dislikes 0	
Response	
The team has representatives that fit in all four registration categories. The team will be considering all members point of view. The SAR scope already appropriately considers "the possibility of adding new or modifying existing NERC Glossary Terms, as the drafting team determines necessary, to ensure clarity in the standard."	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
• We propose a separate standard for IBRs given that IBRs have different technologies. Proposed requirements may need to be articulated specifically to take into account these new technologies. A separate standard will also raise more awareness amongst IBR owners.	

• Given that there are at least two current projects which are associated with misoperations of protection systems (Project 2023-01 EOP-004 for IBR Event Reporting and 2021-04 for PRC-002 Phase II Disturbance monitoring data for IBRs), we recommend that these three projects work closely in coordination.	
Likes 0	
Dislikes 0	
Response	
1. The team agrees that the intent of the SAR can be effectively accomplished by the creation of a new standard and any modifications to an existing Standard(s) as may be needed. 2. The team agrees and will coordinate with other concurrent NERC projects as required.	
Wayne Sippery - 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: a) General Comments: i. The NAGF supports the NERC IRPS recommendation that a new standard be developed that requires analysis and mitigation (to the extent possible) of unexpected or unwarranted control operations from BES inverter-based resources. ii. The NAGF recommends that the references to "protection and control operations" be revised to state "control system performance" throughout the draft SAR document. iii. The NAGF agrees that legacy IBR equipment may not be able to mitigate certain performance issues. Once this is confirmed and communicated, there should be no need to perform repeat root cause analysis and identification of	

possible mitigations for such IBR facilities. Requiring GOs to do such does not provide value and is not an effective/efficient use of GO resources.

iv. The NAGF recommends that the SAR drafting team review existing active NERC Projects such as Projects 2020-02 and 2023-01 to ensure there is no overlap with Project 2023-02.

v. The NAGF recommends that the draft SAR include provisions for a Phase 2 to address reporting of newly registered IBR assets in response to the FERC Order E-1-RD22-4000: Registration of Inverter-Based Resources.

b. Industry Need Section:

i. The NAGF believes that the statement "NERC has also highlighted that many Generator Owners are not aware of these trips" is misleading, is of no value, and does not belong in the draft SAR. The use of the term "trip" is not appropriate to describe an IBR current injection cessation event. Furthermore, due to the speed of IBR electronic controls (milli seconds or less), appropriate data recording equipment would need to be in place to record such events. If such equipment is not in place, GOs would not be aware of current cessation events unless they were long-duration events.

ii. The NAGF agrees that the BA or RC should play a part in defining/determining what disturbances are significant and justifiably warrant an analysis. A GO defined criterion may result in analysis of very insignificant events. In addition, recommend that the draft SAR tie in with Project 2023-01 (EOP-004) to ensure consistency with disturbances requiring analysis.

c. Purpose and Goal Section:

i. Page 2, second paragraph, second sentence – the NAGF requests clarification regarding the statement "…result in widespread reduction of power output…". Is this a reduction on both real and reactive power?

d. Detailed Description Section:

i. Page 3, second paragraph, second sentence – recommend removing " The past few NERC disturbance reports have highlighted limited awareness and understanding by facility owners that abnormal performance has even occurred and therefore" for the reasons described in b.i. above.

ii. Page 4, first paragraph – recommend removing language after "IRPS believes that all BES IBR generation facilities should be applicable to this standard". Remaning language is not in scope for this project.

iii. Page 4, second paragraph, first sentence – the NAGF notes that the draft language "for any reason" is too broad and conflicts with other sections of the draft SAR that specifically identify the event types to be addressed.

e. Cost Impact Assessment Section:

i. The NAGF notes that the costs of adding additional monitoring equipment, engineering/analytical capabilities, and coordination with equipment manufacturers is significant and not adequately addressed in this section. NAGF members have provided the following information:

$50K for monitoring equipment to be installed per inverter. For a 160MW solar facility, there are approximately 64 inverters. $50K X 64 = $3.2 M.

ii. The NAGF recommends that the second sentence starting with "This type of activity…" be removed as it does not provide value for describing the potential cost impacts.

Likes 0	
Dislikes 0	

Response

a)

i. The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both.

ii. The team believes abnormal performance can contain both protection mis operation and control system failures. Limiting the scope of the SAR to include only control system performance at this early stage may lead to the SAR not meeting the intended reliability objectives.

iii. The SAR project scope includes this consideration with the language, "Considerations may be needed for legacy facilities, but the root cause analysis of the abnormal performance and determination of any mitigating measures should be conducted."

iv. The team agrees with the recommendation to coordinate with other active projects.

v. The team believes that the SAR, as it is written, adequately considers this.

B.

i. The SDT believes that the language adds value to the SAR the GO often is unaware of the performance of the IBR. The BA and RC needs authority to point out events and require analysis of unit performance, whether it be a turbine or inverter trip or momentary cessation.
ii. The team has representatives that fit in all four registration categories. The team will be considering all members point of view. The team agrees with the recommendation to coordinate with other active projects.

C.
The team has modified the SAR to reflect this comment.

D.

i. The language adds value to the SAR by identifying the current interdependencies. This is needed thorough communication between all applicable registration functions.
ii. Thank you for comment, the team agrees with the suggestion /edits to the SAR. The second portion of the first sentence was retained to help clarify why facility size is a concern. The team has updated and redlined the SAR to reflect these changes.

iii. The team believes that the definition of abnormal or unexpected performance for events that require analysis. The team has modified the SAR to reflect these changes in the redline.
E.
i. This team will coordinate with other active projects and costs will be balanced with the monitoring need. The team will coordinate with relevant NERC drafting teams, including the team working on Modifications to PRC-002/ PRC-028, to the extent required.
ii. Thank you for the comment, this sentence is reinforcing the first to the sentence. The team did not feel had enough reasoning necessary to remove. Thank you for the suggestion.

Wesley Yeomans - New York State Reliability Council - 10	
Answer	
Document Name	
Comment	

The requirement in the SAR is written in such a way that an unreliable event first takes place prior to any action on the part of the GO/GOP. It is suggested that the GO/GOP should be required to analyze its IBR and reach out to inverter and plant controller manufactures to determine and attest to its ride-through characteristics before a disturbance occurs.

Likes 0	
Dislikes 0	

Response

The team agrees with the comment, this is being addressed in existing standards and standards under modifications that pertain performance standards. One example is 2020-02 Modifications to PRC-024 Ride Through. A NERC alert was issued in March regarding this topic, R-2023-03-14-01 Inverter-Based Resource Performance Issues.

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	

Document Name	
Comment	

Duke Energy suggests:

1. The development of a new NERC Reliability Standard to specifically address IBR issues. In addition to IBRs, Duke Energy would encourage other renewable resources be part of the SAR or an additional SAR proposed for other sources (e.g. synchronous condensers and wind generators).

2. Adding an IBR and related definition(s) to the new NERC Reliability Standard and NERC Glossary of Terms.

3. The new NERC Reliability Standard not be limited to BES definition component minimum threshold limits (e.g., connected at a voltage of 100 kV or above) for power producing resources.

4. Clarifying if the term “performance” is only related to tripping and misoperation or whether it means any type of general operational performance.

(Note: Some references in the SAR indicate ‘events’ and others ‘loss events’; a loss event is much more discernable and definable than the broad range of occurrences included by the general reference, ‘event’. The discussion in the Scope section seems to use this general type of ‘performance’, which could be difficult to define).

If both types of performance are included for trips and failures to meet expected performance, it may be worth considering separating these categories into two SARs. Trips seem to be the most critical at the moment (and may be the focus of this SAR) and tends to align philosophically with PRC-004 which uses terms like ‘misopeations’ and “interrupting device operation” rather than ‘performance.’

5. This SAR coordinate with the work contemplating changes to the 75 MVA reporting limit.

6. SAR proposes the BA and RC have a voluntary role in initiating analysis of abnormal performance. Duke Energy believes the the BA and RC role should be mandatory.

Likes 0	

Dislikes 0	
Response	
1. The team agrees that the intent of the SAR can be effectively accomplished by the creation of a new standard and any modifications to an existing Standard(s) as may be needed. The SAR and associated standard will cover all IBRs including specific wind generator types as appropriate. However, the team believes that elements such as synchronous condensers are outside the scope of this SAR/standard and may be better addressed at the individual facility functional specification level. 2. The SAR scope already appropriately considers "the possibility of adding new or modifying existing NERC Glossary Terms, as the drafting team determines necessary, to ensure clarity in the standard. 3. The team agrees and believes that this will be addressed under the NERC GO-IBR initiative. The team will review this comment appropriately while drafting the standard to ensure that there are no gaps. 4. The team believes that the scope of the SAR is broad enough to capture any unexpected, unwarranted, or unreliable operational performance. The team has representatives that fit in all four registration categories. The team will be considering all members point of view. The team will consider the tradeoffs related to the size of events for analysis.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
Nothing futher at this time.	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	
Document Name	
Comment	
FirstEnergy believes a new Reliability Standard that specifically addresses IBR performance would be the best approach.	
Likes 0	
Dislikes 0	
Response	
The team believes that the modification of the standards outside of PRC-004 may be needed. We believe this can be accomplished by the creation of a new standard, modification to an existing Standard(s) or some combination of both.	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	

Answer	
Document Name	
Comment	
AZPS recommends that references to updating the existing PRC-004 (or other standards) be removed from the SAR.	
Likes 0	
Dislikes 0	
Response	
The team believes that the modification of standards outside of PRC-004 may be needed. We believe that this can be accomplished by the creation of a new standard, modification to existing standard(s), or some combination of both.	

End of Report

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Nomination Form

Project 2023-02 Performance of IBRs Drafting Team

Do not use this form for submitting nominations. Use the electronic form to submit nominations for **Project 2023-02 Performance of IBRs** drafting team (DT) members by **8 p.m. Eastern, Thursday, March 23, 2023.** 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 Standards Developer, Dominique Love (via email), or at 404-217-7578.

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
This project addresses the reliability-related need and benefit by requiring analysis and mitigation of unexpected or unwarranted protection and control operations from inverter-based resources following the identification of such a performance issue. This includes any types of protections or controls that result in abnormal performance issues within the plant, including abnormal performance resulting in anomalous behavior of active power output from the facility during events. Considerations may be needed for legacy facilities, but the root cause analysis of the abnormal performance and determination of any mitigating measures should be conducted. The SAR should be applicable to all Bulk Electric System (BES) inverter-based generating resources, including battery energy storage resources.

These changes will prompt analysis of IBR loss events following grid disturbances to ensure that facilities are operating in a reliable manner and providing essential reliability services. Mitigating actions will reduce unnecessary IBR tripping or controls issues that result in widespread reduction of power output from these facilities, and will also reduce the possibility of systemic performance issues in the future. The result will produce one deliverable:

- Modifications to PRC-004-6 (or a new standard) – focus on IBRs to ensure that any unexpected ceasing of current injection (partial or full) is analyzed by the applicable Generator Owner and mitigated to the extent possible.

Standard affected: PRC-004-6
The time commitment for this project is expected to be up to two 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 review or drafting team sets forth. Team members may also have side

projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

For this project, NERC is seeking individuals who possess experience in one or more of the following areas:

- Generation Owners of Inverter-Based Resources;
- Transmission and Generation Operations;
- Planning and Reliability Coordination;
- Transmission Planning;
- Balancing Authorities;
- Familiarity with NERC Standard PRC-004;
- Other tasks for identifying, analyzing, and mitigating reliability issues for BES Inverter-Based Resources.

Name:	
Organization:	
Address:	
Telephone:	
Email:	
Please briefly describe your experience and qualifications to serve on the requested Standard 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: a		
☐ 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:	

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Standards Announcement

Project 2023-02 Performance of IBRs

Nomination Period Open through March 23, 2023

Now Available

Nominations are being sought for **Project 2023-02 Performance of IBRs** drafting team members through **8 p.m. Eastern, Thursday, March 23, 2023**.

Use the electronic form to submit a nomination. Contact Cindy Jackson 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.

The time commitment for this project is expected to be two 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 review or drafting team sets forth. Team members may also have side projects, either individually or by sub-group, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

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 May 2023. 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, Dominique Love (via email), or at 404-217-7578. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-02 Performance of IBRs” 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 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:	Analysis and Mitigation of BES Inverter-Based Resource Performance Issues		
Date Submitted:	12/06/2022		
SAR Requester			
Name:	Julia Matevosyan, ESIG, IRPS Chair Rajat Majumder, Orsted, IRPS Vice Chair		
Organization:	NERC Inverter-based Resource Performance Subcommittee (IRPS)		
Telephone:	Julia – 512-994-7914 Rajat – 321-390-0333	Email:	julia@esig.energy RAMAJ@orsted.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?):			
Multiple NERC disturbance reports[1] have identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that these pose. These are strongly highlighted in the recent disturbance reports from 2021 including the Odessa disturbance report.[2] IBRs may trip for many different reasons, may cease current injection due to inverter controls, or may have unwanted plant-level controller interactions. These types of issues have been extensively documented in the NERC reports. The resulting unexpected and unwarranted loss of generation poses a significant risk to BPS reliability.			

[1] https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx
[2] https://www.nerc.com/pa/rrm/ea/Pages/May-June-2021-Odessa-Disturbance.aspx

Requested information

Unlike synchronous generation, IBRs can reduce power output very quickly based on the power electronic controls and protections, and the reduction does not necessarily require the operation of an ac circuit breaker or other Protection System (as defined by the NERC Glossary of Terms). The current PRC-004 is focused mainly on conventional Protection Systems and ensures that misoperations are analyzed and mitigated. However, this type of analysis and mitigation is not occurring for inverter-based resources for the reasons described above, and has led to the systemic performance issues documented in NERC disturbance reports.

Rather than complicate the existing PRC-004 focused on Protection Systems, IRPS believes that a new standard should be developed specific to IBRs to ensure that any unexpected ceasing of current injection (partial or full) is analyzed by the applicable Generator Owner and mitigated to the extent possible. NERC has also highlighted that many Generator Owners are not aware of these trips, and that the Balancing Authority or Reliability Coordinator may often identify the unexpected or unwarranted tripping issues. Therefore, it is important that the BA or RC have the authority to identify abnormal performance issues which should then initiate analysis and mitigations by the GO. To be clear, the SAR is not proposing that the BA or RC is responsible for identifying these events; rather, the SAR is proposing that the BA and RC have the ability and authority to voluntarily initiate analysis of the abnormal performance issues by the asset owner (i.e., the GO). It is important that the GO is accountable for analyzing these events, has necessary monitoring equipment installed, and cooperates with the BA/RC by providing operational data and analytical results.

Some legacy equipment may not be able to mitigate performance issues; however, these events should be analyzed with root causes of misoperation identified and possible mitigating actions (or lack thereof) should be documented for all applicable parties.

Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):

The purpose of this proposed project is to introduce a new standard or modify the existing PRC-004 standard[3] that requires analysis and mitigation of unexpected or unwarranted protection and control operations from inverter-based resources following the identification of such a performance issue. This will ensure that IBR loss events (either through protection or control actions) such as those that have occurred numerous times as documented in the NERC disturbance reports are included in the types of events that must be analyzed and mitigated. Considerations will be given for legacy equipment; however, analysis and documentation of mitigation actions (where possible) should still occur. The project should clarify that any protections and controls within an IBR facility that causes abnormal performance of the facility should be included in this type of analysis.

These changes will prompt analysis of IBR loss events following grid disturbances to ensure that facilities are operating in a reliable manner and providing essential reliability services. Mitigating actions will reduce unnecessary IBR tripping or controls issues which will reduce the possibility of systemic performance issues in the future.

[3] IRPS recommends the development of a new standard; however, this is left up to the drafting team to develop an appropriate solution.

Requested information
Project Scope (Define the parameters of the proposed project):
The scope of this project is to either create a new NERC reliability standard or modify an existing standard[4] that requires IBRs that respond to grid disturbances in an unexpected, unwarranted, and unreliable manner to identify, analyze, and mitigate performance issues that occur within the facility. This includes any types of protections or controls that result in abnormal performance issues within the plant, including abnormal performance resulting in anomalous behavior of active power output from the facility during events. Considerations may be needed for legacy facilities, but the root cause analysis of the abnormal performance and determination of any mitigating measures should be conducted. The IRPS also included the possibility of adding new or modifying existing NERC Glossary Terms, as the drafting team determines necessary, to ensure clarity in the standard. The SAR should be applicable to all BES inverter-based resources.
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[5] 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):
Rather than attempt to significantly modify PRC-004 and change the definition of Protection System, the IRPS believes the best approach is to develop a new NERC standard focused specifically on identifying, analyzing, and mitigating unexpected/abnormal performance issues at IBR facilities. The proposed standard does not intend to modify the existing Protection System definition or PRC-004 since the IRPS knows that this will be extremely complicated and could overcomplicate the matter. The NERC reports highlight the strong need for more proactive analysis of IBR performance issues by facility owners. The past few NERC disturbance reports have highlighted limited awareness and understanding by facility owners that abnormal performance has even occurred, and therefore identification of possible performance issues should be initiated by either the IBR facility owner/operator (i.e., the GO/GOP) or by the transmission entities with a wide-area view (i.e., the TOP, RC, or BA). However, the onus of analysis and development of mitigating actions should be on the asset owner to eliminate the possible risk of repeated abnormal performance issues. IRPS recognizes that legacy equipment may not be able to eliminate or fully mitigate performance issues at those facilities; however, analysis and determination of any possible mitigations should be explored and reported to the TOP, RC, and BA and documented by the GO/GOP. This will ensure that possible mitigating actions are fully explored and communicated to all necessary parties.

[4] This is left up to the standard drafting team to ensure sufficient flexibility in developing an appropriate solution. IRPS recommends the creation of a new NERC Standard focused specifically on IBR-specific issues so as to avoid conflating these issues with conventional protection systems installed across transmission networks.

[5] 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

IRPS believes that all BES IBR generating facilities should be applicable to this standard as these issues have been observed across generators of varying sizes (including numerous resources lower than the BES threshold).

IRPS believes that the issues requiring analysis should include any protection or controls that result in abnormal or unexpected performance of the resource. While every possible abnormal performance issue may not be picked up by the GO, GOP, or any transmission entity, any abnormal performance issue identified could result in analysis and possible mitigation. Momentary cessation and IBR tripping for external grid faults should be included in this analysis. Delayed active power recovery following fault ride-through events beyond any applicable standard or mutually agreement should be included in this analysis. Abnormal IBR unit- or plant-level control actions should be included in this analysis. These are all considered unwanted, unexpected, and abnormal and should be explored for corrective actions. The causes of abnormal changes in power output during events (e.g., faults) should include any protections and controls within the IBR, the plant-level controller, and any protection systems within the plant.

IRPS believes that the drafting team should have the flexibility to determine appropriate solutions (i.e., standards language) to codify these concepts in a new NERC Standard. The drafting team may want to explore reporting criteria that avoids unnecessary redundant reporting yet can adequately capture any new performance issues if/when they occur.

IRPS would also like to point out that the NERC reports have highlighted that the protection/controls that "operate as they are programmed" does not necessarily mean correct operation as per interconnection requirements. When a plant trips off-line for an external fault for reasons that are not expected (or allowed per interconnection requirements) nor are likely modeled appropriately in planning assessments, these types of abnormal reductions (tripping, controls, or controller interactions) should be analyzed and mitigated by the GO/GOP in a timely manner. This will likely require the engagement of equipment manufacturers and adequate monitoring data to perform root cause analysis.

Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):

The new standard will require Generator Owners to analyze performance issues identified at their facilities, which may require some engineering and analytical capabilities and additional coordination with equipment manufacturers to determine possible mitigating measures. This type of activity is conducted by all transmission entities, and more commonly conducted by synchronous generator owners (due to the clear operation of an ac circuit breaker tripping a large amount of power with little to no automatic reconnection). Some additional monitoring equipment and capability may be needed at the GO facilities to determine root causes of abnormal performance, which would be reflected with active projects. Due to the systemic nature of risks posed by these issues, the reliability benefits are expected to outweigh the costs for this effort.

Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):

Requested information

The proposed standard project is focused specifically on identifying, analyzing, and mitigating reliability issues for BES inverter-based 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):

The Functional Entities that the proposed standard would apply to are the inverter-based resource Generator Owners. This standard will also give authority to the RC, TOP, or BA to initiate an analysis by a GO if abnormal performance issues are identified.

Additional entities that may provide value to the standard drafting efforts include GOPs, RCs, BAs, TOPs, TPs, and PCs.

Do you know of any consensus building activities[6] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.

This SAR was developed by the NERC IRPS, a consensus-based subcommittee of the NERC Reliability and Security Technical Committee (RSTC). The IRPS developed a white paper[7] as a follow-up to the Odessa disturbance that highlighted the need for this SAR; that white paper was also approved by the RSTC.

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)?

Project 2023-01 EOP-004
Project 2020-02 PRC-024 Ride Through
Project 2021-04 PRC-002/ PRC-028
Project 2020-06 MOD-026, MOD-027

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 disturbance reports have highlighted the need for improved analysis of systemic performance issues from inverter-based resources. NERC IRPS has published numerous guidelines and reports to support industry with recommended monitoring points, performance issues, etc. These activities have not addressed the risk that inverter-based resource owners are not identifying, analyzing, and mitigating abnormal performance issues.

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.

[6] 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.
[7] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Odessa_Disturbance_Follow-Up.pdf

Reliability Principles	
☐	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
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
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

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:	Analysis and Mitigation of BES Inverter-Based Resource Performance Issues		
Date Submitted:	12/06/2022		
SAR Requester			
Name:	Julia Matevosyan, ESIG, IRPS Chair Rajat Majumder, Orsted, IRPS Vice Chair		
Organization:	NERC Inverter-based Resource Performance Subcommittee (IRPS)		
Telephone:	Julia – 512-994-7914 Rajat – 321-390-0333	Email:	julia@esig.energy RAMAJ@orsted.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?):			
Multiple NERC disturbance reports[1] have identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that these pose. These are strongly highlighted in the recent disturbance reports from 2021 including the Odessa disturbance report.[2] IBRs may trip for many different reasons, may cease current injection due to inverter controls, or may have unwanted plant-level controller interactions. These types of issues have been extensively documented in the NERC reports. The resulting unexpected and unwarranted loss of generation poses a significant risk to BPS reliability.			

[1] https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx
[2] https://www.nerc.com/pa/rrm/ea/Pages/May-June-2021-Odessa-Disturbance.aspx

Requested information
Unlike synchronous generation, IBRs can reduce power output very quickly based on the power electronic controls and protections, and the reduction does not necessarily require the operation of an ac circuit breaker or other Protection System (as defined by the NERC Glossary of Terms). The current PRC-004 is focused mainly on conventional Protection Systems and ensures that misoperations are analyzed and mitigated. However, this type of analysis and mitigation is not occurring for inverter-based resources for the reasons described above, and has led to the systemic performance issues documented in NERC disturbance reports. Rather than complicate the existing PRC-004 focused on Protection Systems, IRPS believes that a new standard should be developed specific to IBRs to ensure that any unexpected ceasing of current injection (partial or full) is analyzed by the applicable Generator Owner and mitigated to the extent possible. NERC has also highlighted that many Generator Owners are not aware of these trips, and that the Balancing Authority or Reliability Coordinator may often identify the unexpected or unwarranted tripping issues. Therefore, it is important that the BA or RC have the authority to identify abnormal performance issues which should then initiate analysis and mitigations by the GO. To be clear, the SAR is not proposing that the BA or RC is responsible for identifying these events; rather, the SAR is proposing that the BA and RC have the ability and authority to voluntarily initiate analysis of the abnormal performance issues by the asset owner (i.e., the GO). It is important that the GO is accountable for analyzing these events, has necessary monitoring equipment installed, and cooperates with the BA/RC by providing operational data and analytical results. Some legacy equipment may not be able to mitigate performance issues; however, these events should be analyzed with root causes of misoperation identified and possible mitigating actions (or lack thereof) should be documented for all applicable parties.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The purpose of this proposed project is to introduce a new standard or modify the existing PRC-004 standard[3] that requires analysis and mitigation of unexpected or unwarranted protection and control operations from inverter-based resources following the identification of such a performance issue. This will ensure that IBR loss events (either through protection or control actions) such as those that have occurred numerous times as documented in the NERC disturbance reports are included in the types of events that must be analyzed and mitigated. Considerations will be given for legacy equipment; however, analysis and documentation of mitigation actions (where possible) should still occur. The project should clarify that any protections and controls within an IBR facility that causes abnormal performance of the facility should be included in this type of analysis. These changes will prompt analysis of IBR loss events following grid disturbances to ensure that facilities are operating in a reliable manner and providing essential reliability services. Mitigating actions will reduce unnecessary IBR tripping or controls issues which ~~that result in widespread reduction of power~~

[3] IRPS recommends the development of a new standard; however, this is left up to the drafting team to develop an appropriate solution.

Requested information
~~output from these facilities, and~~ will ~~also~~ reduce the possibility of systemic performance issues in the future.
Project Scope (Define the parameters of the proposed project):
The scope of this project is to either create a new NERC reliability standard or modify an existing standard[4] that requires IBRs that respond to grid disturbances in an unexpected, unwarranted, and unreliable manner to identify, analyze, and mitigate performance issues that occur within the facility. This includes any types of protections or controls that result in abnormal performance issues within the plant, including abnormal performance resulting in anomalous behavior of active power output from the facility during events. Considerations may be needed for legacy facilities, but the root cause analysis of the abnormal performance and determination of any mitigating measures should be conducted. The IRPS also included the possibility of adding new or modifying existing NERC Glossary Terms, as the drafting team determines necessary, to ensure clarity in the standard. ~~Battery energy storage resources, as generating resources, should also be included in the scope of this project.~~ The SAR should be applicable to all BES inverter-based ~~generating~~ resources.
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[5] 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):
Rather than attempt to significantly modify PRC-004 and change the definition of Protection System, the IRPS believes the best approach is to develop a new NERC standard focused specifically on identifying, analyzing, and mitigating unexpected/abnormal performance issues at IBR facilities. The proposed standard does not intend to modify the existing Protection System definition or PRC-004 since the IRPS knows that this will be extremely complicated and could overcomplicate the matter. The NERC reports highlight the strong need for more proactive analysis of IBR performance issues by facility owners. The past few NERC disturbance reports have highlighted limited awareness and understanding by facility owners that abnormal performance has even occurred, and therefore identification of possible performance issues should be initiated by either the IBR facility owner/operator (i.e., the GO/GOP) or by the transmission entities with a wide-area view (i.e., the TOP, RC, or BA). However, the onus of analysis and development of mitigating actions should be on the asset owner to eliminate the possible risk of repeated abnormal performance issues. IRPS recognizes that legacy equipment may not be able to eliminate or fully mitigate performance issues at those facilities; however, analysis and determination of any possible mitigations should be explored and reported to the TOP, RC, and BA and documented by the GO/GOP. This will ensure that possible mitigating actions are fully explored and communicated to all necessary parties.

[4] This is left up to the standard drafting team to ensure sufficient flexibility in developing an appropriate solution. IRPS recommends the creation of a new NERC Standard focused specifically on IBR-specific issues so as to avoid conflating these issues with conventional protection systems installed across transmission networks.

[5] 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
IRPS believes that all BES IBR generating facilities should be applicable to this standard as these issues have been observed across generators of varying sizes (including numerous resources lower than the BES threshold). ~~Therefore, it would not seem logical to raise the size threshold any higher than the BES definition for dispersed power producing resources.~~ IRPS believes that the issues requiring analysis should include any protection or controls that result in abnormal or unexpected performance of the resource~~ for any reason~~. While every possible abnormal performance issue may not be picked up by the GO, GOP, or any transmission entity, any abnormal performance issue identified could result in analysis and possible mitigation. Momentary cessation and IBR tripping for external grid faults should be included in this analysis. Delayed active power recovery following fault ride-through events beyond any applicable standard or mutually agreement should be included in this analysis. Abnormal IBR unit- or plant-level control actions should be included in this analysis. These are all considered unwanted, unexpected, and abnormal and should be explored for corrective actions. The causes of abnormal changes in power output during events (e.g., faults) should include any protections and controls within the IBR, the plant-level controller, and any protection systems within the plant. IRPS believes that the drafting team should have the flexibility to determine appropriate solutions (i.e., standards language) to codify these concepts in a new NERC Standard. The drafting team may want to explore reporting criteria that avoids unnecessary redundant reporting yet can adequately capture any new performance issues if/when they occur. IRPS would also like to point out that the NERC reports have highlighted that the protection/controls that "operate as they are programmed" does not necessarily mean correct operation as per interconnection requirements. When a plant trips off-line for an external fault for reasons that are not expected (or allowed per interconnection requirements) nor are likely modeled appropriately in planning assessments, these types of abnormal reductions (tripping, controls, or controller interactions) should be analyzed and mitigated by the GO/GOP in a timely manner. This will likely require the engagement of equipment manufacturers and adequate monitoring data to perform root cause analysis.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The new standard will require Generator Owners to analyze performance issues identified at their facilities, which may require some engineering and analytical capabilities and additional coordination with equipment manufacturers to determine possible mitigating measures. This type of activity is conducted by all transmission entities, and more commonly conducted by synchronous generator owners (due to the clear operation of an ac circuit breaker tripping a large amount of power with little to no automatic reconnection). Some additional monitoring equipment and capability may be needed at the GO facilities to determine root causes of abnormal performance, which would be reflected with active projects. Due to the systemic nature of risks posed by these issues, the reliability benefits are expected to outweigh the costs for this effort.

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):
The proposed standard project is focused specifically on identifying, analyzing, and mitigating reliability issues for BES inverter-based 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):
The Functional Entities that the proposed standard would apply to are the inverter-based resource Generator Owners. This standard will also give authority to the RC, TOP, or BA to initiate an analysis by a GO if abnormal performance issues are identified. Additional entities that may provide value to the standard drafting efforts include GOPs, RCs, BAs, TOPs, TPs, and PCs.
Do you know of any consensus building activities[6] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This SAR was developed by the NERC IRPS, a consensus-based subcommittee of the NERC Reliability and Security Technical Committee (RSTC). The IRPS developed a white paper[7] as a follow-up to the Odessa disturbance that highlighted the need for this SAR; that white paper was also approved by the RSTC.
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)?
~~N/A~~ Project 2023-01 EOP-004 Project 2020-02 PRC-024 Ride Through Project 2021-04 PRC-002/ PRC-028 Project 2020-06 MOD-026, MOD-027
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 disturbance reports have highlighted the need for improved analysis of systemic performance issues from inverter-based resources. NERC IRPS has published numerous guidelines and reports to support industry with recommended monitoring points, performance issues, etc. These activities have not addressed the risk that inverter-based resource owners are not identifying, analyzing, and mitigating abnormal performance issues.

[6] 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.
[7] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Odessa_Disturbance_Follow-Up.pdf

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
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
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 9
Standards Committee
December 13, 2023

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

Action

- Approve the following waiver of provisions of the Standard Processes Manual (SPM) for Project 2023-02:
  - 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 little as 15 days, with ballot conducted during the last 10 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 project addresses the reliability-related need by requiring analysis and mitigation of unexpected or unwarranted protection and control operations from Invert-Based Resources (IBRs). This includes any types of protections and controls that result in abnormal performance issues within the plant, including abnormal performance resulting in anomalous behavior of active power output from the facility during events. The SAR focuses on revisions to PRC-004-6 and should be applicable to all Bulk Electric System (BES) IBR generating resources, including battery storage.

At the January 25, 2023 meeting, the Standards Committee (SC) accepted the Standard Authorization Request (SAR) that was submitted by the Inverter-Based Resource Performance Subcommittee and authorized soliciting members for the Drafting Team (DT). The informal comment period and the solicitation for the drafting team members ran from February 22–March 23, 2023. The DT was appointed at the June 21, 2023 SC meeting. During the October SC meeting, the SC accepted the redlined SAR.

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 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, including 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 of three 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 2023-02 DT leadership and NERC staff request that the SC approve a waiver for certain provisions of the SPM regarding the length of comment periods and ballots in order to meet the November 2024 development deadline for 2023-02 as established by FERC.

Summary

Project 2023-02 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 2023-02 DT leadership and NERC staff recommend shortening 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-030-1 is posted for a 25-day formal comment period with initial ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 25, 2023
SAR posted for comment	February 22, 2023 – March 23, 2023

Anticipated Actions	Date
25-day formal comment period with initial ballot	March 25 – April 18, 2024
15-day formal or informal comment period with additional ballot	TBD
05-day final ballot	TBD
Board adoption	August 14 - 15, 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:** Unexpected Inverter-Based Resource Event Mitigation
2. **Number:** PRC-030-1
3. **Purpose:** Identify, analyze, and mitigate unexpected Inverter-Based Resource change of power output.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Generator Owner
   - **4.2. Facilities:**
     - **4.2.1.** Bulk Power System (BPS) Inverter-Based Resources (IBR)
5. **Effective Date:** See Implementation Plan for PRC-030-1

B. Requirements and Measures

R1. Each applicable Generator Owner shall have a documented process to identify unexpected changes[1] in power output occurring within a two-second period and is the greater of either 20% of the plant's gross nameplate rating, or 20 MVA. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each applicable Generator Owner shall have evidence which may include but is not limited to: (1) a documented process for detecting unexpected changes in output as described in Requirement R1, (2) actual data recordings, and (3) identification of gross nameplate rating.

R2. Each applicable Generator Owner shall implement its process established in Requirement R1 to identify unexpected changes in power output. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence of implementation may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the applicable Generator Owner implemented its process established in Requirement R1.

R3. Each applicable Generator Owner shall provide data when requested from its Balancing Authority, Reliability Coordinator, or Transmission Operator regarding IBR responses during an identified system level event within 30 calendar days of the receipt of the request. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each applicable Generator Owner shall have evidence as specified in Requirement R3 which may include, but is not limited to, dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

R4. Each applicable Generator Owner shall analyze its IBRs performance within 45 calendar days of either the event identified pursuant to Requirement R2 or receipt of a request pursuant to Requirement R3. The analysis shall include all of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. The cause(s) of unexpected change(s) in power output;

4.2. The applicability to its other IBR facilities that could be affected by the same cause of unexpected change(s) in power output; and

4.3. Notification to each applicable Balancing Authority, Reliability Coordinator, or Transmission Operator of the analysis results.

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[1] Unexpected changes in power output includes any change of generation that is not attributed to factors such as weather patterns, change of wind, change in irradiance, curtailment, ramping, planned outage, planned testing, or the loss of a Transmission Line connecting the IBR generators.

M4. Each applicable Generator Owner shall have dated analysis documentation, developed in accordance with Requirements R4. Evidence may include, but is not limited to: (1) an analysis report, (2) actual data recordings or derivations, (3) documents describing the device specification and device configuration or settings, and (4) plant configuration.

R5. Each applicable Generator Owner shall, within 45 days of completing the analysis in Requirement R4, develop one of the following and provide it to each applicable Reliability Coordinator: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. A Corrective Action Plan (CAP) for the identified Inverter Based Resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R4 Part 4.2; or

5.2. A technical justification that addresses why corrective actions will not be applied nor implemented.

M5. Each applicable Generator Owner shall have dated evidence (electronic or hardcopy format) that demonstrates it developed a CAP or a technical justification, and evidence of transmittal to the Reliability Coordinator in accordance with Requirement R5.

R6. Each applicable Generator Owner shall, for each of its CAPs developed pursuant to Requirement R5: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

6.1. Implement the CAP;

6.2. Update the CAP if actions or timetables change; and

6.3. Notify each applicable Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

M6. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, communication with equipment manufacturers, and communication with each applicable Reliability Coordinator that documents the implementation, updating, or completion of a CAP in accordance with Requirement R5.

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 shall keep data or evidence of Requirement R1, R2, and R3, Measure M1, M2, and M3 for 12 calendar months following the completion of each Requirement.
   - The Generator Owner shall retain evidence of Requirement R4, Measure M4, including any supporting analysis per Requirements R2 and R3, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.
   - The Generator Owner shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

   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 responsible entity failed to have a documented process to identify unexpected changes in power output in accordance with Requirement R1.
R2.	N/A	N/A	N/A	The responsible entity failed to implement the process established in accordance with Requirement R1.
R3.	N/A	N/A	N/A	The responsible entity failed to provide data when requested from its Balancing Authority, Reliability Coordinator, or Transmission Operator.
R4.	The responsible entity performed an analysis in accordance with Requirement R4, but in more than 45 calendar days but less than 60 calendar days of first identifying an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R4, but in 60 or more calendar days but less than 90 calendar days of first identifying an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R4, but in 90 or more calendar days but less than 120 calendar days of first identifying an event or receiving a request. OR The responsible entity performed the analysis in	The responsible entity developed an evaluation in accordance with Requirement R4, but in 120 calendar days or more of first identifying an event or receiving a request. OR The responsible entity performed the analysis in Requirement R4, but failed to

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			Requirement R4, but failed to address one of the Parts 4.1 through Parts 4.3.	address two or more of the Parts 4.1 through Parts 4.3 OR The responsible entity failed to develop an evaluation in accordance with Requirement R4.
R5.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 45 days, but provided within 60 days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 60 days, but provided within 90 days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 90 days, but provided within 120 days OR The developed CAP did not include corrective actions for other facilities owned by the GO as identified in R4.2, if necessary. OR The developed CAP or technical justification was not provided to the applicable RC.	The responsible entity developed a CAP or provide a technical justification why no corrective actions will be implemented, but in 120 calendar days or more. OR The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented.
R6.	The responsible entity implemented, but failed to update a CAP, when actions or	N/A	N/A	The responsible entity failed to implement a CAP in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	timetables changed, in accordance with Requirement R6.			accordance with Requirement R6.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan.

Version History

Version	Date	Action	Change Tracking
Initial Draft	**02/06/2024**	**Draft**	

Implementation Plan

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1

Applicable Standard(s)

- PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation

Requested Retirement(s)

- None

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

Applicable Entities

- Generator Owner (GO)

Background

After Project 2023-02 was underway, FERC issued No. Order 901[1] that directs the development of new or modified reliability standards, including 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[2]. Within the work plan, NERC identified three active Standards Development Projects that would need to be filed for regulatory approval with FERC November 4th, 2024. These projects include 2020-02 Modifications to PRC-024 (Generation Ride Through)[3], 2021-04

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

[2] 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

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

Modifications to PRC-002-2[4], and 2023-02 Analysis and Mitigation of BES Inverter-Based Resources Performance Issues[5].

General Considerations

The key development for applicable Functional Entities is a process to capture change in power events for IBR resources. The requested implementation timeline allows for ample time for entities to draft and implement their process. The information required for Standard compliance is currently available to Generator Owners.

Effective Date

The effective date for the proposed Reliability Standard is provided below.

Standard PRC-030-1

Where approval by an Applicable Governmental Authority is required, Reliability Standard PRC-030-1 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, Reliability Standard PRC-030-1 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.

[4] 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

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

Technical Rationale

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1 | March 2024

PRC-030-1 – Unexpected Inverter-Based Resource Event Mitigation

Rationale for Applicability Section

The functional entity responsible for identifying, analyzing, and mitigating unexpected Inverter Based Resources (IBR) performance is the Generator Owner (GO). This standard intentionally did not include requirements for the Balancing Authority (BA), Reliability Coordinator (RC), and Transmission Operator (TOP) because other standards (e.g., EOP-004) place requirements on these entities for system level events.

Rationale for Requirement R1

The intent of Requirement R1 is for the Generator Owner (GO) to self-identify events that are sufficiently large enough to analyze for proper performance of the facility under those conditions. The Reliability Standard provides a framework for the GO to proactively identify, analyze, and as necessary, mitigate unexpected performance. Also note that there is an alternative path of event identification by the BA, RC, or TOP. It is expected that the combination of both identification methods would identify events of concern.

The standard intentionally refers to power output to include both active and reactive power. It recognizes current changes are associated with power output variations. All these parameters are useful characteristics that can be used for event identification.

Nameplate rating was used as the basis of the change (power or amperes) because it is the common reference in NERC and other industry standards.

The 20% magnitude of event threshold was chosen to be large enough to screen out normal operational events but not so large that it does not detect events that should be analyzed.

For smaller capacity facilities, the use of only a percent change as the screening criteria would lead to identification of disturbances that are not likely to be significant for analysis. The 20 MVA minimum sets a lower threshold for event identification.

The two second time period, the fastest Supervisory Control and Data Acquisition (SCADA) scanning rate, was chosen to provide a frame of reference for sudden events versus normal operations. The intent is to screen out events such as those discussed in footnote one of the Standard. The footnote addresses expected changes during normal operations that should not be classified as an event, such as weather

patterns, change of wind, change in irradiance, curtailment, ramping, planned outage, planned testing, or due to the loss of a Transmission Line connecting the IBR generators.
The intent is not to focus on the expected energy output of the facility, but the expected response of the facility to the event. The context of unexpected change is related to the proper and intended response of the facility to the event, based on the interconnection requirements and facility design. Once the performance of the IBR is analyzed, the response will be evaluated as expected or unexpected.

The Drafting Team (DT) selected the term "unexpected changes" to encompass both unexpected decreases (i.e., loss) and unexpected increases (i.e., additions) that may be caused by IBR mis-operations that could affect system reliability. For instance, a battery energy storage system that mis-measures system frequency may unexpectedly enter a charging mode.

Photovoltaic (PV) example 1 – qualifying:
PV facility with gross nameplate rating of 110 MVA is operating with active output of 80 MW and 20 Mvar of reactive power injection (82.5 MVA). During a transmission system fault event[1], the plant exhibits a near instantaneous active power output drop to 50 MW with 10 Mvar injection (51 MVA).

The change in apparent power in under two seconds is 31.5 MVA, which exceeds 22 MVA, the greater of 20% of the plant's gross nameplate (22 MVA) or 20 MVA. This IBR performance event is required to be captured by the GO's Requirement R1 process.

PV example 2 – non-qualifying:
PV facility with gross nameplate rating of 80 MVA is operating with active output of 60 MW and zero Mvar of reactive power exchange (60 MVA). During a transmission line fault event,[1] the plant exhibits a near instantaneous active power output drop to 42 MW and zero Mvar of reactive power exchange (42 MVA).

The change in apparent power in under two seconds is 18 MVA, <u>not</u> exceeding 20 MVA, the greater of 20% of the plant's gross nameplate rating (16 MVA) or 20 MVA. This IBR performance event is <u>not</u> required to be captured by the GO's Requirement R1 process.

Battery Energy Storage System (BESS) example 1 – qualifying:
BESS facility with gross nameplate rating of 80 MVA is operating as a load drawing 50 MW and while producing 20 Mvar of reactive power injection (53.9 MVA). During a power plant controller ("PPC") malfunction event of the BESS facility, the PPC incorrectly estimates system frequency sending an incorrect frequency response signal causing the plant to exhibit a near instantaneous change in real power to 10 MW injection with 20 Mvar injection (22.4 MVA).
The change in apparent power in under two seconds is approximately 31.5 MVA, which exceeds 20 MVA, the greater of 20% of the BESS gross nameplate (16 MVA) or 20 MVA.
This IBR performance event is required to be captured by the GO's Requirements R1 process.

[1] The transmission line fault is assumed not to be on the line connecting the IBR to the system, but rather is a fault remote from the IBR.

BESS example 2 – non-qualifying:
BESS facility with gross nameplate rating of 80 MVA is generating 40 MW and 10 Mvar of reactive power exchange (41.2 MVA). The BESS facility is curtailed by the RC such that the plant exhibits a near instantaneous active power decrease to 15 MW and 10 Mvar of reactive power (18 MVA).
The change in apparent power in under two seconds is 23.2 MVA, exceeding 20 MVA, the greater of 20% of the plant's gross nameplate rating (16 MVA) or 20 MVA. However, the change in apparent power is the result of the RC curtailment which is an exempt event per Requirement R1. This IBR performance event is <u>not</u> required to be captured by the GO's Requirement R1 process.

Rationale for Requirement R2
The reliability objective for Requirement R2 is for applicable entities to utilize the process established in Requirement R1. Utilizing the process ensures a consistent approach to identifying unexpected changes in IBR performance, decreases the possibility of introducing errors, and increases the likelihood of mitigating events.

Rationale for Requirement R3
The purpose of Requirement R3 is to give authority to the BA, RC, or TOP to initiate an analysis by a Generator Owner (GO) if abnormal performance issues are identified. This is essential as the previously stated entities possess a system-wide view, enabling them to identify and capture events in which system disturbances result in an unexpected change in power output from IBRs. These are not readily visible to individual GOs as demonstrated in several NERC Disturbance Reports.

The DT did not place any requirements on the RC, BA, or TOP to identify system level events in this standard because the requirement for BA to identify these events is being developed under EOP-004 in Project 2023-01 IBR Event Reporting. In addition, power systems can vary significantly in terms of size, complexity, IBR penetration, and operational constraints. Allowing BAs, RCs, and TOPs the flexibility to determine thresholds, methods acknowledge this diversity, ensures that the standards can be adapted to suit the specific needs of each system operator.

The intent of this requirement is to promote data sharing and collaboration between the event identifying entity which has area-wide visibility and the GOs. Mitigating activities can be applied proactively to other IBR entities when data sharing takes place. The 30-day time-period was selected to align with Project 2021-04 Modifications to PRC-002-2, in which GOs have a certain number of days to provide high resolution data upon request. The 30-day time-period was also chosen to introduce a time-bound aspect to the process. This ensures prompt analysis once the request has been made by the event identifying entity.

Rationale for Requirement R4
Requirement R4 allows 45 days to analyze expected versus actual IBR responses to place an emphasis on diligent resolution, while still allowing enough time to conduct an analysis and identify causes. Forty-five days allows adequate time for Generator Owners (GO) to interact with manufacturers and examine capabilities of equipment.

The 45-day period starts from the event date for GO-identified performance issues resulting from Requirement R2. For performance issues identified through Requirement R3, the 45-day period starts upon request from the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operator (TOP) regarding IBR responses identified during system events.

Part 4.1 is necessary to analyze and identify the root cause(s) of the problem to determine actions for the Corrective Action Plan (CAP) or to provide technical justification for performing no action, as required by Requirement R5.

Part 4.2 is necessary to analyze and identify systemic issues with other similar IBR designs to ensure that adequate performance is achieved throughout the BPS. Addressing systemic IBR performance issues contributes to maintaining Bulk Power System reliability.

Part 4.3 is necessary to ensure other functional entities are aware of, and potentially account for, the risks associated with IBR performance throughout the BPS. For GO-identified performance issues from R2, the other BA, RC, and TOP may not become aware of these issues without notification through these three entities. For performance issues identified through Requirement R3, the results of the analysis should be communicated to the BA, RC, and TOP to inform these entities of the result and causes of issues identified by these entities.

Rationale for Requirement R5

Resolving the causes of IBR performance issues benefits BPS reliability by preventing recurrence. The CAP is an established tool for resolving operational problems. The NERC *Glossary* defines a Corrective Action Plan as, “A list of actions and an associated timetable for implementation to remedy a specific problem.” Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the IBR Performance issue cause(s) is identified in Requirement R2 or Requirement R3, Requirement R5 requires Generator Owner(s) to develop a CAP or provide a technical justification that addresses why corrective actions will not be applied nor implemented.

This standard recognizes there may be multiple causes for IBR performance issues. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of an IBR performance issues. The 45-calendar day period for developing a CAP or technical justification is established based on industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent IBR performance issues from reoccurring, the timetable for executing such actions, and an evaluation of the CAP’s applicability to the GO’s other IBR including those at other locations. The evaluation of these other IBR with similar designs aims to reduce the risk and the likelihood of similar IBR performance issues in other IBRs. The GO is responsible for determining the extent of its evaluation concerning other IBRs and locations. The evaluation may result in the GO including actions to address IBR at other locations or to provide a technical justification that addresses why corrective actions will not be applied nor implemented.

Acceptable technical justification for not performing corrective actions is expected to primarily fall into two categories:
1) it would require material modifications/qualified change; or
2) interconnection requirements on IBR performance extending beyond those in place at the time of interconnection.
Technical justifications for not performing corrective actions do not relieve the GO from compliance to other standards (i.e., PRC-029-1 Ride-Through) to the extent that it's applicable.

Rationale for Requirement R6

Requirement R6 mandates that each entity implement the CAP developed in Requirement R5 which mitigates the deficiencies identified in Requirement R4. In the NERC *Glossary*, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem."

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. If the CAP is changed, the entity must notify the applicable RC(s), TOP(s), or BA(s). The entity must also notify applicable RC(s), TOP(s) or BA(s) when the CAP has been completed. The implementation of a properly developed CAP ensures that causes of unexpected changes in IBR power output are mitigated in a timely manner.

An IBR deficiency may require the RC, TOP, or BA to impose operating restrictions so the system can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions should incentivize the entity to complete the CAP as quickly as possible.

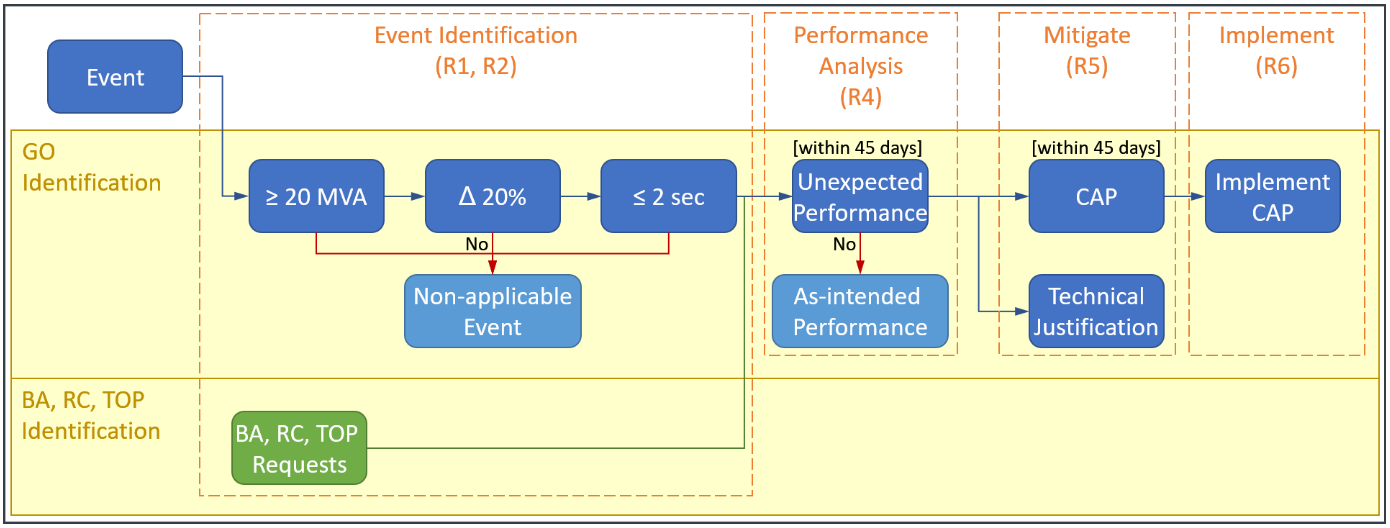

Figure 1.1: PRC-030-1 Flowchart

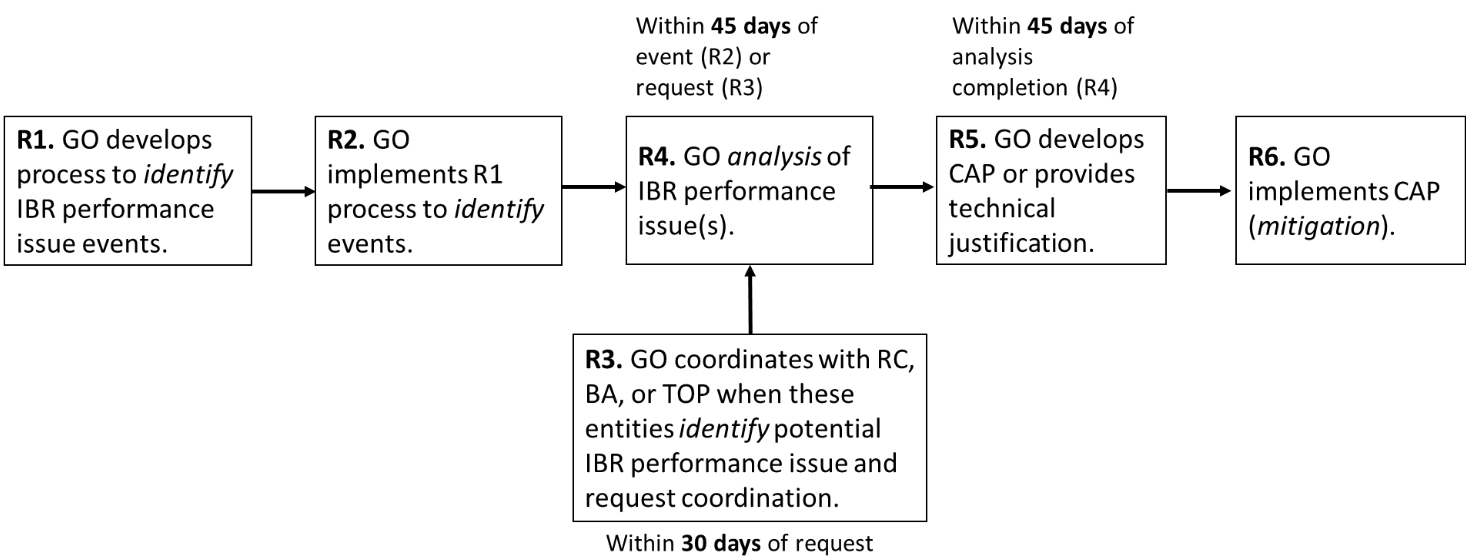

Figure 1.2: Relationship of PRC-030-1

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

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

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on draft one of **PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation** by **8 p.m. Eastern, April 18, 2024.**

Additional information is available on the project page. If you have questions, contact Standards Developer, Josh Blume (email), or at 404-446-2593.

Background Information

Multiple NERC disturbance reports have identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that this undesired performance can pose. Project 2023-02 addresses the reliability-related need by requiring analysis and mitigation of unexpected or unwarranted protection and control operations from IBRs. This includes any types of protections and controls that result in abnormal performance issues within the plant, including abnormal performance resulting in anomalous behavior of active power output from the facility during events.

On October 19, 2023, FERC issued Order No. 901, which directed NERC to develop new or modify existing Reliability Standards that include new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. Project 2023-02 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 a waiver 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 in order to help meet the FERC- directed deadline.

Questions

1. Does the entity believe there should be proposed changes in language in regards to Requirement R1, “to identify unexpected changes”?

   ☐ Yes
   ☐ No

   Comments:

2. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

☐ Yes
☐ No

Comments:

3. Provide any additional comments for the Drafting Team to consider, if desired.

Comments:

Violation Risk Factor and Violation Severity Level Justifications

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

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 Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues. 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 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-030-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because not having a process for identifying unexpected changes in power output, which is required in defining the minimum standards will be performed could directly affect the electrical state or the capability of the Bulk-Power System (BPS), or the ability to effectively monitor and control the BPS. In addition, a violation of this 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. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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 medium 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-030-1, Requirement R1	
Proposed VRF	**Medium**
than One Obligation	

VSLs for PRC-030-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity failed to have a documented process to identify unexpected changes in power output in accordance with Requirement R1.

VSL Justifications for PRC-030-1, 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.
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-030-1, Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because not implementing the process for identification unexpected change in power output, which are required in defining the minimum standards will be performed could directly affect the electrical state or the capability of the Bulk-Power System (BPS), or the ability to effectively monitor and control the BPS. In addition, a violation of this 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. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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 medium 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-030-1, Requirement R2	
Proposed VRF	**Medium**
than One Obligation	

VSLs for PRC-030-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity failed to implement the process established in accordance with Requirement R1.

VSL Justifications for PRC-030-1, 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	The proposed VSL is binary and does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-030-1, 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	The VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-030-1, Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because not coordinating and cooperating with a request from the Generator Owner's Balancing Authority, Reliability Coordinator, or Transmission Operator regarding a system level event, within 30 days, could directly affect the electrical state or the capability of the Bulk Power System (BPS),or the ability to effectively monitor and control the BPS. In addition, a violation of this 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. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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.

VRF Justifications for PRC-030-1, Requirement R3	
Proposed VRF	**Medium**
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 medium 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-030-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity failed to coordinate and cooperate with requests from its Balancing Authority, Reliability Coordinator, or Transmission Operator.

VSL Justifications for PRC-030-1, Requirement R3	
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-030-1, Requirement R3	
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 VSL is binary and does 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	The VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-030-1, Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because a Generator Owner not analyzing it’s Inverter Based Resource’s performance which are required in defining the minimum standards will be within 45 days of an event,

VRF Justifications for PRC-030-1, Requirement R4	
Proposed VRF	**Medium**
	identified pursuant to Requirement R2 or receipt of a request pursuant to Requirement R3, to address the unexpected change(s) in power output and the applicability to its other IBR facilities that could be affected by the same cause of unexpected change(s) in power output could directly affect the electrical state or the capability of the Bulk Power System (BPS), or the ability to effectively monitor and control the BPS. In addition, a violation of this 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. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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 medium 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-030-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performs an analysis in accordance with Requirement R4, but in more than 45 calendar days but less than 60 calendar days of first identifying an event or receiving a request.	The responsible entity performs an analysis in accordance with Requirement R4, but in 60 or more calendar days but less than 90 calendar days of first identifying an event or receiving a request.	The responsible entity performs an analysis in accordance with Requirement R4, but in 90 or more calendar days but less than 120 calendar days of first identifying an event or receiving a request. OR The responsible entity performed the analysis in Requirement R4, but failed to address one of the Parts 4.1 through Parts 4.3.	The responsible entity developed an evaluation in accordance with Requirement R4, but in 120 calendar days or more of first identifying an event or receiving a request. OR The responsible entity performed the analysis in Requirement R4, but failed to address two or more of the Parts 4.1 through Parts 4.3 OR The responsible entity failed to develop an evaluation in accordance with Requirement R4.

VSL Justifications for PRC-030-1, 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.

VSL Justifications for PRC-030-1, Requirement R4	
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 not 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-030-1, Requirement R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because a Generator Owner's failure to develop either a Corrective Action Plan (CAP), or technical justification that addresses why corrective actions will not be applied nor implemented for it's Inverter Based Resource's could directly affect the electrical state or the capability of the Bulk Power System

VRF Justifications for PRC-030-1, Requirement R5	
Proposed VRF	**Medium**
	(BPS), or the ability to effectively monitor and control the BPS. In addition, a violation of this 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. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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 medium 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-030-1, Requirement R5

Lower	Moderate	High	Severe
The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 45 days, but provided within 60 days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 60 days, but provided within 90 days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 90 days, but provided within 120 days Or: The developed CAP did not include corrective actions for other facilities owned by the GO as identified in R4.2, if necessary. Or: The developed CAP or technical justification was not provided to the applicable RC.	The responsible entity developed a CAP or provided a technical justification why no corrective actions will be implemented, but in 120 calendar days or more. Or: The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented.

VSL Justifications for PRC-030-1, 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	The proposed VSLs are not 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-030-1, Requirement R5	
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.

VRF Justifications for PRC-030-1, Requirement R6	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because failure to implement, update, or notify with the applicable Reliability Coordinator (RC) the Corrective Action Plan (CAP) for it's Inverter Based Resource's could directly affect the electrical state or the capability of the Bulk Power System (BPS), or the ability to effectively monitor and control the BPS. In addition, a violation of this 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. Therefore, it is in line with the definition of a Medium VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.

VRF Justifications for PRC-030-1, Requirement R6	
Proposed VRF	**Medium**
Blackout Report	
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The assignment of Medium 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 medium 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-030-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

VSL Justifications for PRC-030-1, Requirement R6	
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 not 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
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RELIABILITY CORPORATION

Standards Announcement

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

Formal Comment Period Open through April 18, 2024
Ballot Pools Forming through April 3, 2024

Now Available

A 25-day formal comment period for draft one of **PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation,** is open through **8 p.m. Eastern, Thursday, April 18, 2024.**

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.

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.

Ballot Pools
Ballot pools are being formed through **8 p.m. Eastern, Wednesday, April 3, 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 standard and implementation plan, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **April 9 – 18, 2024**.

For 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 470-755-0346. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues 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:	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues | Draft 1
Comment Period Start Date:	3/25/2024
Comment Period End Date:	4/18/2024
Associated Ballots:	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Implementation Plan IN 1 OT 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues PRC-030-1 IN 1 ST

There were 66 sets of responses, including comments from approximately 180 different people from approximately 120 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Does the entity believe there should be proposed changes in language in regards to Requirement R1 “to identify unexpected changes”?

2. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

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
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
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
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
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
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	SERC
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Scott Berry	Wabash Valley Power Association	3	RF
					Sara Orr	Golden Spread Electric Cooperative, Inc.	5	Texas RE
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC

					Jolly Hayden	East Texas Electric Cooperative, Inc.	NA - Not Applicable	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 Corporation	6	RF
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
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
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
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	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 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 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. Does the entity believe there should be proposed changes in language in regards to Requirement R1 “to identify unexpected changes”?

Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	

WAPA isn’t a GO, however we support the MRO NSRFs feedback:

- Need to ensure that PRC-030 R1 does not include balance of plant (BOP) Protection System already covered under PRC-004-6. An example would be PV & wind generation 34.5kV collection system Protection Systems. This should be addressed in the §4. Applicability as follows “4.2.1. the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.”
- The threshold should simply be a magnitude e.g. 20MVA. Anything less then 20MVA would not affect the Bulk Electrical System pursuant to the definition and is the accepted threshold within industry. This would also more closely align with GADS Event reporting thresholds. In addition, the MRO NSRF would like to understand the justification of why apparent power is the magnitude being used by the SDT?
- 2 second time period. The MRO NSRF does not agree with the rationale for 2s time period “The two second time period, the fastest Supervisory Control and Data Acquisition (SCADA) scanning rate…”. The MRO NSRF suggests “within one-minute” time period. The time period shall start when the first individual generating unit is lost. This aligns with the time-frame traditionally used and this ensure that the events that need to be analyzed are captured without having multiple events or over analysis.

Alternative:

- 2 second time period. The MRO NSRF does not agree with the rationale for 2s time period “The two second time period, the fastest Supervisory Control and Data Acquisition (SCADA) scanning rate…”. The MRO NSRF suggests “within 30 seconds” time period. The time period shall start when the first individual generating unit (ibr) is lost. The MRO NSRF suggests reviewing Project 2023-01 EOP-004 IBR Event Reporting, Technical Rationale document for EOP-004-5.
- The MRO NSRF does not agree with Requirement R2 “documented process to identify unexpected changes”. Generator Owners need to analyze “unexpected changes” that meet a threshold. Having a process is unnecessary, not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit.

Likes 0	
Dislikes 0	
Response	

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	

On the surface, this seems like a reasonable standard to produce practices surrounding event archiving and heighten reliability from the IBR resources. IBR resources are still in their adolescence and their event interactions with the system are not well understood or foreseen at this time. This raises questions about the timing of these changes. There are also questions surrounding the financial solvency of the current IBR market. Will the market still look the same in 5-10 years? How will these changes impact a market that looks completely different a few years from now?

IPCO strongly encourages NERC to find a way to better address the relationship with the vendor, or Long Term Service Agreement Administrator, to ensure that the entity is only held responsible for those things that is within their control in this process. IPCO understands this is a challenging process to navigate but encourage NERC to draft the standard in a way that recognizes and allows flexibility around time frames dictated in PRC-030.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

FirstEnergy supports EEI's comments.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	No
Document Name	

Comment

Tri-State Generation and Transmission supports MRO NSRFs comment.

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	No
Document Name	

Comment

AZPS supports that following comments that were submitted by EEI on behalf of it's members:

EEI does not support the proposed language in Requirement R1 due to the following concerns:

1. The use of the term "unexpected changes" adds ambiguity and subjectivity to the requirement and should be removed.

2. The use of footnotes places clarifying information outside of the requirement and should be brought directly into Requirement R1.

3. We suggest replacing "power" with Real Power in order to align with the NERC defined term.

4. EEI asks that the SDT provide some justification for the proposed event trigger (i.e., greater of either 20% of the plant's gross nameplate rating, and at least 20 MVA).

5. We suggest combining Requirements R1 with R2, similar to other NERC Reliability Standards, in order to negate the need to have a requirement that requires an entity to document a process (R1) and another to implement that process (R2).

6. EEI notes that the SAR states that "[m]ultiple NERC disturbance reports have identified the undesired performance of bulk power system (BPS) connected inverter-based resources (IBRs) during grid faults" yet the proposed Requirement R1 would have IBR GOs capture data on any "unexpected change" on IBR power output. While a laundry list of exclusions is provided, IBR GOs will still have to capture and analyze any event that meets the criteria of R1 and determine why the drop in power output occurred and then save all of the event data except those events that meet the identified exclusions. If left unchanged this will result in a substantial new burden on IBR owners to collect and analyze significant amounts of data that in many cases will not be relatable to any system faults. Necessitating more staff and unrecoverable costs to support this effort, while not achieving the desired improvement in BPS Reliability.

While EEI offers the following as clearer language for what has been proposed for Requirement R1, we note that a Requirement such as proposed or aligned with our proposed changes will be very costly and burdensome to IBR GOs. Moreover, the only way to minimize the burden of capturing this data would be to tie these events to system disturbances, which is the root cause of IBR aberrant performance but would require GOs to have ready access to system disturbance information, which may be impractical:

R1. Each Generator Owner shall implement one or more documented process(es) to capture and retain IBR system telemetry and IBR alarms data necessary for analyzing IBR performance during IBR or Unit IBR events where there is a decrease in Real Power output that is equal to or greater than 20% of the power output of the IBR or IBR Unit, but not less than 20MW, occurring over a two-second period. IBR and Unit IBR telemetry and alarm data captured during a specified IBR or Unit IBR event, determined by the responsible IBR GO, to have been the result of one of the following conditions negates the need for the IBR GO to retain the captured data: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1 Losses in IBR or Unit IBR associated with weather, such as changes in wind, solar irradiance, etc.; or

1.2 Load curtailments, resource ramping, planned outages, planned resource testing; or

1.3 Loss of a transmission line connecting the IBR or Unit IBR.

To address the issue of system disturbance identification within IBR control systems, identified above, the SDT should coordinate with the Project 2021-04 (PRC-028-1) SDT to determine whether Disturbance Monitoring Equipment that will be required under that project could provide triggers into IBR control systems so that IBR Telemetry and IBR system alarms could be efficiently linked with disturbance event seen at IBR facilities. Such

linkage, if feasible, would minimize IBR GO data collection, as well as provide useful information that would assist IBR GOs in understanding the impact of disturbances on their equipment while improving their ability to develop Requirement R5 CAPs that efficiently resolve performance issues.	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
The list provided in the Footnote (1) of the Standard for unexpected power output changes is pretty exhaustive and I can't think of anything to add to it.	
Likes 1	Snohomish County PUD No. 1, 3, Chaney Holly
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) agrees with the proposed language in Requirement 1 and doesn't believe there should be changes.	
Likes 0	
Dislikes 0	
Response	
Patricia Ireland - DTE Energy - 4, Group Name DTE Energy	
Answer	No
Document Name	
Comment	

The language in R1 of the standard related to the definition of unexpected changes is clear. However, the “two-second” period requires additional definition before we can implement appropriate detective controls. We assume that this time period refers to two-second intervals rather than any two-second span, or is this up to each entity to determine? We would appreciate clarification prior to submittal for board approval.

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

The power output change monitored should be MW rather than MVA. System voltage transient conditions may drive the reactive output temporarily up or down in exceedance of the criteria thresholds, and monitoring of this regulation response is not the object of this standard drafting effort.   All previous system disturbance response evaluations performed by NERC have focused on the MW loss from facilities due to disturbances.   The event evaluations prescribed by this draft standard should also focus on unexpected MW changes.

Southern Company recommends that R1 be eliminated and R2 be modified to include the specifics of the process found in R1 in the R2 requirement to implement a process to identify unexpected changes.

The 2-second time frame is quicker than most EMS SCADA polling rates. The EMS SCADA data could miss an event that is longer than two (2) sec, but shorter than the EMS scan rate. Was this time frame selected to not include events where the IBR plant returns to the pre-disturbance condition in less than two (2) seconds?

Likes 0	
Dislikes 0	

Response

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1

Answer	No
Document Name	

Comment

Please see response in Question 3.

Likes 1	Tallahassee Electric (City of Tallahassee, FL), 5, Weaver Karen
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy suggests the implementation of the following Duke Energy, EEI and NAGF review comments. Duke Energy EEI and NAGF comment modifications are bracketed by asterisks.

EEI COMMENTS

EEI does not support the proposed language in Requirement R1 due to the following concerns:

1. The use of the term "unexpected changes" adds ambiguity and subjectivity to the requirement and should be removed.

2. The use of footnotes places clarifying information outside of the requirement and should be brought directly into Requirement R1.

3. We suggest replacing "power" with Real Power to align with the NERC defined term.

4. EEI asks that the SDT provide some justification for the proposed event trigger (i.e., greater of either 20% of the plant's gross nameplate rating, or 20 MVA). *****Suggest using 20 MW or 20 MVAr as threshold event triggers, instead of the stated 20% of the plant's gross nameplate rating or 20 MVA triggers.*****

5. EEI notes that the SAR states that "[m]ultiple NERC disturbance reports have identified the undesired performance of bulk power system (BPS) connected inverter-based resources (IBRs) during grid faults" yet the proposed Requirement R1 would have IBR GOs capture data on any "unexpected change" on IBR power output. While a laundry list of exclusions is provided, IBR GOs will still have to capture and analyze any event that meets the criteria of R1 and determine why the drop in power output occurred and then save all of the event data except those events that meet the identified exclusions. If left unchanged this will result in a substantial new burden on IBR owners to collect and analyze significant amounts of data that in many cases will not be relatable to any system faults. Necessitating more staff and unrecoverable costs to support this effort, while not achieving the desired improvement in BPS Reliability.

While EEI offers the following as clearer language for what has been proposed for Requirement R1, we note that a Requirement such as proposed or aligned with our proposed changes will be very costly and burdensome to IBR GOs. Moreover, the only way to minimize the burden of capturing this data would be to tie these events to system disturbances, which is the root cause of IBR aberrant performance but would require GOs to have ready access to system disturbance information, which seems impractical:

R1. Each Generator Owner shall have a documented process to **capture and retain IBR system telemetry and IBR alarms data necessary for analyzing IBR performance during IBR or Unit IBR events where there is a decrease in Real** Power output **that is equal to or greater than 20% of the power output of the IBR or IBR Unit, but not less than 20MW,** occurring over a two-second period**. IBR and Unit IBR telemetry and alarm data captured during a specified IBR or Unit IBR event, determined by the responsible IBR GO, to have been the result of one of the following conditions negates the need for the IBR GO to retain the captured data:** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1 Losses in IBR or Unit IBR associated with weather, such as changes in wind, solar irradiance, etc.; or

1.2 Load curtailments, resource ramping, planned outages, planned resource testing; or

1.3 Loss of a transmission line connecting the IBR or Unit IBR.

An alternative solution to the above would be to link the capture of IBR telemetry and system alarms to system disturbance events as identified within the Disturbance Monitoring Equipment that will be required at IBR facilities under Project 2021-04 (PRC-028-1). It is EEI's understanding that output triggers could be programmed within this equipment to directly tie drops in Real Power output to system disturbances. This would significantly reduce the requirement for data capture within PRC-030-1.

NAGF COMMENTS

The NAGF does not support the proposed language for Requirement R1 and provides the following comments for consideration:

a. The 2 second timeframe to identify unexpected changes in power output may not be possible for existing inverter-based resource (IBR) facilities. *****It's also our opinion that events which recover within the 2 second timeframe should not require assessment. GOs with large fleets having to assess every response which falls into the 2 second timeframe would result in an enormous effort to review.*****

b. The NAGF requests that the 20MVA threshold be revised to reference MW *****or MVAr***** instead of MVA.

c. The NAGF notes that PRC-004: Protection System Misoperation Identification and Correction does not require a documented process to identify misoperations, rather it requires applicable registered entities to identify misoperations and take actions accordingly. Therefore, the NAGF recommends that the proposed PRC-030 Requirement R1 be deleted or modified to align with PRC-004.

d. The NAGF notes that Requirement R1 “shall have a documented process” is purely an administrative documentation effort that provides no benefit to reliability. Note that Paragraph 81 efforts eliminated such administrative burdens from the NERC Reliability Standards and as such the DT should not be including such administrative activities in the proposed PRC-030.

e. Recommend moving footnote #1 – unexpected changes in output criteria as items listed under Requirement R1.

f. The NAGF notes that the process and activities proposed under Requirement R1 and R2 better aligns with Generator Operator (GOP) responsibilities rather than Generator Owner (GO).

Likes 0	
Dislikes 0	

Response

Dave Krueger - SERC Reliability Corporation - 10

Answer	No
Document Name	

Comment

On behalf of the SERC Generator Working Group:

Suggest eliminating requirement to develop a process and change the threshold levels found in R1 and include that in R2. For R1, suggest changing to MW from MVA so an event isn't triggered on normal voltage swings

Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
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	No
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	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	

• PRC-004-6 already covers balance of plant (BOP) Protection System disturbances, so some distinction needs to be provided to direct activities to be completed under PRC-004 and those to be completed under this standard.

• The disturbance threshold should be described in MW, not MVA (20MW not 20 MVA).

o Additional cost to calculate MVA that our controllers do not currently perform.

• The 2-second time period is too short. Most SCADA systems in North America utilize a 2-second or slower scan time. Therefore, it is quite conceivable that events might not be captured with the current SCADA configuration. If the situation rights itself in 2-seconds, then it probably does not need to be studied.

o Any calculations that are required to be added to determine MVA would further increase the time period and make the proposed 2 second time period to fast.

o The disturbance time period should be more like one minute and should commence with the loss of the first generating unit. If it is a genuine issue, then it will last for 60 seconds.	
Likes 0	
Dislikes 0	
Response	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
In general Vistra agrees with Entergy's comments. We believe the wording is too ambiguous and we would like to see more guidance provided on the expected process. It would help to add more specifics, i.e. "if there is a power output drop during a system disturbance that does not return to pre disturbance levels." We agree that PRC-004-6 already covers most of the collector substation so perhaps PRC-029 should only cover the IBR units? 2 seconds may be too short and the SCADA justification is weak, 30 to 60 seconds may be more be more reasonable.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP recommends footnote 1 be modified to indicate that unexpected changes in power are calculated as the change from the average of multiple power readings for a period of greater than or equal to 0.1 second.	
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 supports the NAGF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
BC Hydro appreciates the drafting team's efforts and the opportunity to comment, and offers the following comments. BC Hydro suggests that additional clarification may be beneficial on scenarios that could constitute an 'expected change'. A transmission line outage may obfuscate situations where IBRs output unexpectedly drops prior to the line trip, e.g. some Type 4 machines use technology to allow for negative sequence contribution. For a scenario where a windfarm with this technology that doesn't provide negative sequence current during a connecting transmission outage and subsequent transmission line trip – would this be considered an 'unexpected change in generator output' or an 'expected change in generator output'?	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Clarify what the "loss of a Transmission Line connecting the IBR generator" refers to. Does it only refer to the generator lead line? Does it only cover if a generator is on a radial transmission line? The loss of either the generator lead line or a radial transmission line connecting the IBR would result in the disconnection of the IBR and not create any unexpected changes. If the IBR is connected to more than one transmission line, the IBR should not have unexpected changes. An IBR generator should respond to system topology changes as expected through offline studies. Strengthen the standard by expanding R1 to cover events that the RC or TOP identify. This allows for multiple entities to identify events. Also, the RC or TOP can request data from the GO for events (R3) and the GO needs to analyze events pursuant to R3 (R4). Using the gross nameplate rating for a threshold could miss events from large IBRs that are operating at a low output. Change the threshold to be 20% of pre-event MW output.	

Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Generation is typically measured in MW not MVA	
Likes 0	
Dislikes 0	
Response	
Srinivas Kappagantula - Arevon Energy - 5	
Answer	Yes
Document Name	
Comment	

Arevon Energy does not support the proposed language for Requirement R1 and provides the following comments for consideration:

1. The 2 second timeframe to identify unexpected changes in power output may not be possible for exiting inverter-based resource (IBR) facilities. The 2 second timeframe is too short. Morst SCADA systems utilize a 2-seconr or slower scan time. Hence, most events might not even be captured within the current SCADA configurations. If the situation rights itself in 2-seconds, then it probably doesnt require to be studied.

2. The disturbance threshold should be described in MW not MVA, most plant owners/operators deal in MW not necessarily talk about a plant in MVA.

3. PRC-004-6 already covers balance of plant (BOP) equipment and related Protection System disturbances. There needs to be some distinction between the activities that need to be performed under PRC-004 and those that this standard is proposing to be studied.

4. R1 is purely administrative in nature and of no reliability benefit. Having a documented process for a performance standard isnt required. Paragraph 81 efforts eliminated such administrative burdens from the NERC Reliability Standards and as such the SDT should not be including such administrative activities in the proposed PRC-030. A good example is PRC-004, which does not require a documented process to identify misoperations, rather it requires applicable registered entities to identify misoperations and take actions accordingly. PRC-030 should align with the approach PRC-004 takes. Essentially delete R1 and make R2 a requirement to identify the unexpected changes in power output.

5. The term "unexpected changes" needs more clarification. While the footnote provides some context, it does not provide enough clarification. For example, the footnote does not include faults. Is the expectation that the GO would document each time the plant reacts to a fault? Arevon Energy recommends removing the footnote and including the criteria under R1 as a list to avoid any ambiguity. The SDT shoudl focus on what should be included in "unexpected changes" rather than simply listing exclusions.

6. The process and activities proposed under Requirement R1 and R2 may better align with Generator Operator (GOP) responsibilities rather than Generator Owner (GO).

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	Yes
Document Name	

Comment

Enel North America Inc. (Enel) would like to thank the Standard Drafting Team for their efforts in developing this reliability standard. Enel does not agree with the language in Requirement R1 for the following reasons:

First, a documented process is not necessary for compliance and does not align with similar standards, e.g. PRC-004-6. Enel believes that a documented process for this standard is administrative in nature, does not support reliability, and is needlessly burdensome (NERC's "Paragraph 81" criteria as set forth in 138 FERC ¶ 61,193 at P81 (2012)).

Second, regarding the time-period to identify an applicable event, Enel believes that the two-second period is too short. The technical rationale for the time-period is arbitrary and based on hardware capability rather than industry-accepted standards that establish a minimum scanning rate. Such a short time-period would necessitate storing large amounts of data, i.e. large volume of discrete data points, to be kept for upwards of 45 days, accounting for currently drafted analysis requirements, Requirement R4. Enel would suggest the SDT provide further justification to support the time-period that is reflective of events experienced by IBRs, e.g. Odessa or leverage established industry standards.

Third, the 20 MVA threshold should be changed to align with GADS Event reporting, loss of at least of 20MW of Plant Total Installed Capacity.

Likes 0	
Dislikes 0	

Response

Megan Melham - Decatur Energy Center LLC - 5

Answer	Yes
Document Name	

Comment

Capital Power supports NAGF's comments.

The NAGF does not support the proposed language for Requirement R1 and provides the following comments for consideration:

a. The 2 second timeframe to identify unexpected changes in power output may not be possible for existing inverter-based resource (IBR) facilities.

b. The NAGF requests that the 20MVA threshold be revised to reference MW instead of MVA. As currently drafted, there does not appear to be any value gained from having to calculate the MVA before doing any analysis.

c. The NAGF notes that PRC-004: Protection System Misoperation Identification and Correction does not require a documented process to identify misoperations, rather it requires applicable registered entities to identify misoperations and take actions accordingly. Therefore, the NAGF recommends that the proposed PRC-030 Requirement R1 be deleted or modified to align with PRC-004.

d. The NAGF notes that Requirement R1 "shall have a documented process" is purely an administrative documentation effort that provides no benefit to reliability. Note that Paragraph 81 efforts eliminated such administrative burdens from the NERC Reliability Standards and as such the DT should not be including such administrative activities in the proposed PRC-030.

e. Recommend moving footnote #1 – unexpected changes in output criteria as items listed under Requirement R1.

f. The NAGF notes that the process and activities proposed under Requirement R1 and R2 better aligns with Generator Operator (GOP) responsibilities rather than Generator Owner (GO).

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	Yes
Document Name	

Comment

The footnote describing what are not "unexpected changes" does not consider small (<5%) system voltages changes caused by shunt reactor or capacitor switching. This means, an IBR plant operating at constant MW (low wind conditions or vars at standstill) but regulating voltage could generate frequent (daily) "unexpected change" events by simply regulating voltage, as planned, and required.

A MW requirement instead of MVA would allow to remove all the unwanted error reporting linked to voltage regulation, especially during continuous operating conditions.

Likes 0	
Dislikes 0	

Response

Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

Yes. As currently defined in footnote 1, “unexpected changes” appears to include BPS events that an IBR responds to *correctly*. For example, a BPS fault occurs and an IBR dynamically responds to the fault event correctly (within 2 seconds) and the IBR returns back to normal pre-disturbance conditions. As currently written in the standard, this type of response would be deemed an “unexpected change” when in fact it is the expected change/performance for an IBR based on interconnection requirements and facility design. Requiring event analysis, or event just the determination of “expected versus unexpected change” for every single fault event across the entire IBR fleet would result in an exorbitant cost and burden to GOs. Elevate does not believe this is necessarily the perspective or intent of the SDT and therefore wants to stress this technical aspect so that this is clarified for the benefit of all stakeholders.

An example of a change to the “unexpected changes” footnote to address this aspect is detailed below:

“Unexpected changes in power output includes any change of generation that is not attributed to factors such as weather patterns, change of wind, change in irradiance, curtailment, ramping, planned outage, planned testing, the loss of a Transmission Line connecting the IBR generators, or expected/intended dynamic responses to grid events.”

As mentioned, Requirement R1 also defines the unexpected changes in power output “occurring within a two-second period.” While the “within two-second period” is being set to capture dynamic, fast-moving events (e.g., fault events, transients, etc.) rather than the slower expected changes like weather patterns/changes, curtailment, ramping, etc. (i.e. the excluded events), we have a concern that the “within two-second period” will catch all dynamic responses of IBRs to any event on the system, including correct/intended dynamic responses (rather than just capturing abnormal or unexpected response). Furthermore, the “within two-second period” characterization may miss controller oscillations, control interactions, and slower active or reactive power responses in the wrong direction than intended. These types of unexpected changes should be identified and analyzed as part of this new standard as well. Examples of industry references and requirements of these types of events include: (a) the IEEE 2800-2022 standard, specifically clause 7.2.2.6 “Restore Output After Voltage Ride-Through”, which provides active power recovery time following BPS disturbances in the range of 1.0 second to 10 second; and (b) the NERC Reliability Guideline for BPS-Connected IBR Performance provides information on IBR responses occurring longer than two-seconds such as automatic return to service following a trip.

Providing guidance in Requirement R1 for the trigger of the events of concern is a good practice but limiting the requirement language to specify only one trigger (e.g., the “unexpected changes in power output occurring with a two-second period”) to capture any type of unexpected changes with an IBR will likely result in many types of events being missed, while also capturing many events that don’t need to be analyzed (e.g., correct/intended responses of an IBR). The recommendation would be to include a set of event triggers as sub-requirements under Requirement R1.

Example triggers could include:

(1) unexpected changes in active or reactive power output within a two-second period*

(2) unexpected changes in active or reactive power output longer than a two-second period, including momentary cessations and tripping of the IBR plant or individual IBR units.

(3) Active or reactive power oscillations that are poorly damped or persist for longer than *[consider value]* seconds;

*Note: This is incumbent on the recommended change to “unexpected change” footnote that excludes the *expected* response to grid events.

This structure would give the opportunity for additional triggers to be easily added and implemented/considered to more suitably capture unexpected operations occurring from IBRs on the BPS.

Likes 0	
Dislikes 0	

Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	

Ameren believes the threshold in R1 is too low and suggests changing it to 75 MVA to align with PRC-004. We also suggest inserting the phrase "related to a common cause" in the footnote after the word "generation." We also think R3 should be removed as it is redundant with reporting requirements in MOD-032. The new Category 2 registration also creates redundancy within the standard. In the Facilities sections, we believe Bulk Power System should be changed to Bulk Electric System because this term is used more frequently and is better understood. We also think event detection would be too burdensome with the current requirements in R1. Finally, if an IBR is on the Distribution system, is that part of the BPS? In general, Ameren also agrees with EEI's and NAGF's comments.

Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	

The MRO NSRF provides the following feedback:

- Need to ensure that PRC-030 R1 does not include balance of plant (BOP) Protection System already covered under PRC-004-6. An example would be PV & wind generation 34.5kV collection system Protection Systems. This should be addressed in the §4. Applicability as follows "4.2.1. the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition." MRO NSRF requests that the SDT clearly articulate what equipment is within scope for this standard, with special attention paid to any potential overlaps with PRC-030 and PRC-004-6.
- The threshold should simply be a magnitude e.g. 20MVA. Anything less than 20MVA would not affect the Bulk Electrical System pursuant to the definition and is the accepted threshold within industry. This would also more closely align with GADS Event reporting thresholds. In addition, the MRO NSRF would like to understand the justification of why apparent power is the magnitude being used by the SDT?
- 2 second time period. The MRO NSRF does not agree with the rationale for 2s time period "The two second time period, the fastest Supervisory Control and Data Acquisition (SCADA) scanning rate…". The MRO NSRF suggests "within one-minute" time period. The time period shall start when the first individual generating unit is lost. This aligns with the time-frame traditionally used and this ensure that the events that need to be analyzed are captured without having multiple events or over analysis.
- The MRO NSRF does not agree with Requirement R1 "documented process to identify unexpected changes". Generator Owners need to analyze "unexpected changes" that meet a threshold. Having a process is unnecessary, not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit.

Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	

Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the concerns expressed in the EEI comments for this question.	
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 the NAGF position in which it does not support the proposed language for Requirement R1 and provides the following comments for consideration:

a. The 2 second timeframe to identify unexpected changes in power output may not be possible for existing inverter-based resource (IBR) facilities.

b. The NAGF requests that the 20MVA threshold be revised to reference MW instead of MVA.

c. The NAGF notes that PRC-004: Protection System Misoperation Identification and Correction does not require a documented process to identify misoperations, rather it requires applicable registered entities to identify misoperations and take actions accordingly. Therefore, the NAGF recommends that the proposed PRC-030 Requirement R1 be deleted or modified to align with PRC-004.

d. The NAGF notes that Requirement R1 "shall have a documented process" is purely an administrative documentation effort that provides no benefit to reliability. Note that Paragraph 81 efforts eliminated such administrative burdens from the NERC Reliability Standards and as such the DT should not be including such administrative activities in the proposed PRC-030.

e. Recommend moving footnote #1 – unexpected changes in output criteria as items listed under Requirement R1.

f. The NAGF notes that the process and activities proposed under Requirement R1 and R2 better aligns with Generator Operator (GOP) responsibilities rather than Generator Owner (GO).

Likes 0	
Dislikes 0	
Response	

Scott Thompson - PNM Resources - 1,3 - WECC,Texas RE

Answer	Yes
Document Name	

Comment

PNM agrees with EEI's comments

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	Yes
Document Name	

Comment

Constellation recommends additional language in R1 requirement to add “ occurring withing two-second period or the minimum possible evaluation period with the existing site equipment, not to exceed XXX , and is greater” to add flexibility to the requirement.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5

Answer	Yes
Document Name	

Comment

The language in R1 of the standard related to the definition of unexpected changes is clear. However, the “two-second” period requires additional definition before we can implement appropriate detective controls. We assume that this time period refers to two-second intervals rather than any two-second span, or is this up to each entity to determine? We would appreciate clarification prior to submittal for board approval.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	Yes
Document Name	

Comment

- MH requests that the SDT clearly articulate what equipment is within scope for this standard, with special attention paid to any potential overlaps with PRC-030 and PRC-004-6.
- MH suggests modifying the R1 to read "Each applicable Generator Owner shall have a documented process to identify unexpected changes1 in power output occurring within a **60-**second period **as result of system disturbance event(s)** and is the greater of either 20% of the plant's gross nameplate rating, or 20 MVA.
- 2 second time period. The MH does not agree with the rationale for 2s time period "The two second time period, the fastest Supervisory Control and Data Acquisition (SCADA) scanning rate…". The MH suggests "within 60-seconds" time period. The time period shall start when the first individual generating unit is lost or reduced as result of system event(s). This aligns with the time-frame traditionally used and this ensure that the events that need to be analyzed are captured without having multiple events or over analysis.

Likes 0	
Dislikes 0	

Response

Michael Goggin - Grid Strategies LLC - 5

Answer	Yes
Document Name	

Comment

In addition to listing event causes that need not be identified in footnote 1, it may be easier for R1 to specify the types of events that should be screened for further analysis. For example, R1 could require identification of 20 MW/20% drops in output within two seconds due to "unexpected behavior of generator settings and controls," or similar language. The Standard could also GADS forced outage cause codes to clarify which types of outages are to be identified and which are not to be identified. A major concern is that, without greater clarity on the type of events that are to be identified, manually reviewing all events to exclude the event types discussed in the footnote will create a huge compliance burden. For example, the passage of clouds over small to medium solar plants can cause changes in output of 75% of nameplate capacity per second,[1] so the generator operator needs a way to automatically exclude those events from consideration by having greater clarity on the types of events that are to be screened for.

{C}[1] https://www.sciencedirect.com/science/article/abs/pii/S0306261917300144

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	

AEPC signed on to ACES comments:

ACES appreciates the effort put forth by the SDT in drafting the newly proposed PRC-030-1 Reliability Standard. Crafting an entirely new standard is no small undertaking and we are grateful for the hard work and dedication of the SDT members. ACES believes that draft 1 is an excellent step towards meeting the requirements of FERC Order 901; however we contend that the current language would benefit from a few modifications.

From a historical perspective, the Reliability Standards have used MVA to classify generating units and to establish a threshold for applicability. Megawatts (MW) is typically used to quantify the changes in generation output and load (e.g., Most Severe Single Contingency, Reporting ACE, EOP-004, MOD-031, CIP-002 Impact Rating, etc.). It is the opinion of ACES that it would be best for PRC-030-1 to conform to the established convention and utilize MW in lieu of MVA when identifying these event types.

Additionally, it is the opinion of ACES that the phrase “unexpected changes” is overly broad so as to capture what is arguably an edge case scenario. Per the Technical Rationale, the intent of the SDT was to:

“encompass both unexpected decreases (i.e., loss) and unexpected increases (i.e., additions) that may be caused by IBR mis-operations that could affect system reliability. For instance, a battery energy storage system that mis-measures system frequency may unexpectedly enter a charging mode.”

It is our position that the greater risk to the reliability of the BES is from an unexpected decrease in generation not an unexpected increase. We do acknowledge that unexpected increases in generation may also pose a reliability risk to the BES; however, we contend that this has always been the case for all generation types and the incidence rate is statistically insignificant. Using a modified version of the example provided by the SDT in the portion of the Technical Rationale quoted above, please consider the following hypothetical scenario:

- A pumped storage hydro generating unit with a gross nameplate rating of 480 MVA is operating with an active output of 435 MW and 20 MVAR (435.5 MVA).
- During a control system malfunction event, the control system incorrectly calculated system frequency sending an incorrect frequency response signal causing the unit to exhibit a near instantaneous change in power output (note: this control action is commonly called “droop control”).
    - The resulting change in power output is a full 5% step change resulting in a final output of 456.75 MW and 20 MVAR (457.2 MVA).
- The change in apparent power in under 2 seconds is 21.7 MVA.
    - While this is less than 20% of the unit’s gross nameplate rating, it is greater than the minimum 20 MVA threshold specified in PRC-030-1 R1.

Thus, it is our assertion that the risk to the BES from an unexpected increase of 20 MVA is immateria to the generating resource type that caused said increase. In short, we believe that this standard should remain focused only on sudden, unexpected losses caused by IBRs at this time. We believe this approach would more closely align with PRC-004-6.

Lastly, it is ACES’ opinion that the parameters identifying these types of events should be modified to more closely align with the language used in the most recent revision of EOP-004-5. Therefore, we recommend that R2 be struck in its entirety and R1 be modified to use the following language:

“Each Generator Owner that identifies an unexpected loss of aggregated Electrical Energy output at an applicable facility (per Section 4.2) shall, within 120 calendar days, determine if the unexpected loss meets the criteria identified in Part 1.1 and Part 1.2.

1.1 Occurs within a 30-second period and

1.2 Greater than either (whichever is larger):

1.2.1 20% of the IBR's Normal Rating or 1.2.2 20 megawatts (MW)"	
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), North American Generator Forum (NAGF), and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 1	
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	
The Standards Drafting Team (SDT) needs to ensure that the proposed new Reliability Standard PRC-030-1 does not overlap with the purpose and requirements of PRC-004-6 - Protection System Misoperation Identification and Correction, in which the "unexpected changes in power output" of an IBR are not attributable to a protection system operation or misoperation. This could be accomplished by revising Footnote 1 to state, "Unexpected changes in power output includes any change of generation that is not attributed to factors such as weather patterns, change of wind, change in irradiance, curtailment, ramping, planned outage, planned testing, *protection system operation*, or the loss of a Transmission Line connecting the IBR generators".	

In addition, Requirement R1 limits the identification of unexpected power changes to those "occurring within a two-second period" and does not consider slower, unanticipated IBR control system interactions that may cause power oscillations. Two seconds is not long enough for average SCADA systems to quantify the unexpected power changes.

SMUD recommends that the time period be increased to "a 60-second period" to allow for greater detection of unanticipated IBR control system interactions that affect the Bulk Electric System.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	Yes
Document Name	

Comment

Constellation recommends additional language in R1 requirement to add " occurring withing two-second period or the minimum possible evaluation period with the existing site equipment, not to exceed XXX , and is greater" to add flexibility to the requirement.

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	Yes
Document Name	

Comment

The NAGF does not support the proposed language for Requirement R1 and provides the following comments for consideration:

a. The 2 second timeframe to identify unexpected changes in power output may not be possible for existing inverter-based resource (IBR) facilities.

b. The NAGF requests that the 20MVA threshold be revised to reference MW instead of MVA. As currently drafted, there does not appear to be any value gained from having to calculate the MVA before doing any analysis.

c. The NAGF notes that PRC-004: Protection System Misoperation Identification and Correction does not require a documented process to identify misoperations, rather it requires applicable registered entities to identify misoperations and take actions accordingly. Therefore, the NAGF recommends that the proposed PRC-030 Requirement R1 be deleted or modified to align with PRC-004.

d. The NAGF notes that Requirement R1 “shall have a documented process” is purely an administrative documentation effort that provides no benefit to reliability. Note that Paragraph 81 efforts eliminated such administrative burdens from the NERC Reliability Standards and as such the DT should not be including such administrative activities in the proposed PRC-030.

e. Recommend moving footnote #1 – unexpected changes in output criteria as items listed under Requirement R1.

f. The NAGF notes that the process and activities proposed under Requirement R1 and R2 better aligns with Generator Operator (GOP) responsibilities rather than Generator Owner (GO).

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	Yes
Document Name	

Comment

WEC Energy Group does not agree with the 20% or 20 MVA threshold. The technical rationale states that “was chosen to be large enough to screen out normal operational events but not so large that it does not detect events that should be analyzed”. We do not agree that it is large enough to screen out normal events. The SAR discusses “misoperations” due to grid disturbances. The thresholds in R1 would capture more events than misoperations due to grid disturbances.

WEC Energy Group proposes that the threshold should be set to at least 75% of the site nameplate for BES IBRs and 20 MVA for Non-BES IBRs to only capture site misoperations/faults. The loss of generation in past disturbances was largely contributed by sensitive IBR trip protection settings and impacted the entire site. The disturbance reports clearly support that R1 should state and mandate evaluation for site misoperations/faults based on thresholds or system disturbance identified by TP, PC, RC, or TO.

In addition, as it’s currently proposed, the requirement of R1 will be difficult to identify. Logic that’s necessary to filter out “unexpected changes” attributed to weather patterns, change of wind and/or change in irradiance factors will be difficult to develop and costly.

The “unexpected changes” attributed to weather patterns, change of wind and/or change in irradiance factors occur on a daily basis in some geographical regions, often multiple times per day and can easily drop the site output by 20MVA.

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 feels that it may be appropriate for this requirement to apply to all generators larger than 20 MVA, not just IBRs. Unexpected power swings on all generators need to be explored and mitigated as the risk to each interconnection is similar. SRP's suggestion is to remove BPS IBR facility verbiage in the facilities portion of the applicability section or add language to include all units. SRP also recommends the standard title be changed to Unexpected Power Output Event Mitigation. Lastly, SRP would like Out of Management Control (OMC) to the factors of power output changes in Note 1.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
WECC suggests that the SDT should emphasize language to ensure that MVAR support, if lost, is captured as an event as “power output” may be interpreted as simply MWs.WECC also believes the SDT should use the proposed definition of Inverter-Based Resource and not add terms (e.g., IBR “generator”). Note that Project 2023-01 EOP-004 describes power output loss differently and limits it to MW—"The Responsible Entity is not required to report losses due to weather patterns, lack of wind, change in irradiance, fuel unavailability, curtailment, ramping, planned outage, planned testing, failure of SCADA or Telemetering data, or due to the loss of a radial transmission facility that disconnects the IBR generators. WECC believe the SDTs should collaborate and use same language to describe conditions and criteria.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the concerns expressed in the EEI comments for this question.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	

Answer	Yes
Document Name	
Comment	

Minnesota Power supports MRO’s NERC Standards Review Forum’s (NSRF) comments.

Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	
Comment	

Electric Reliability Council of Texas, Inc. (ERCOT) recommends that the threshold for what constitutes an unexpected change under Requirement R1 be modified to be the ***lesser*** of either 20% of the plant’s gross nameplate rating, or 20 ***MW***. This would ensure that units with a rating larger than 100 MW would assess events down to 20 MW. The 20% threshold would set the floor for units with a rating of less than 100 MW, which would be appropriate. Under the currently proposed language for Requirement R1, a 500 MW plant would not be required to analyze a 90 MW unexpected change, which is a change that is larger than the full rating of some entire units. This outcome would not be consistent with the objectives of the standard.

ERCOT recommends that MW be used as the unit of measurement instead of MVA because MVA includes both real and reactive power. Most IBRs operate in reactive priority mode, which means that MVAR will adjust as needed during the two-second window to support voltage, which may skew any MVA-based measurements. Most ride-through performance failure issues are related to unnecessary tripping of the IBR plant or units or abnormal reduction in active current during the ride-through, both of which would result in unexpected changes in MW output. If the SDT believes unexpected changes in MVAR output should also be assessed, ERCOT recommends that this be addressed separately in a dedicated Requirement with its own criteria to avoid confusion or misapplication.

Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	
Comment	

EEI does not support the proposed language in Requirement R1 due to the following concerns:

1. The use of the term “unexpected changes” adds ambiguity and subjectivity to the requirement and should be removed.
2. The use of footnotes places clarifying information outside of the requirement and should be brought directly into Requirement R1.
3. We suggest replacing “power” with Real Power in order to align with the NERC defined term.
4. EEI asks that the SDT provide some justification for the proposed event trigger (i.e., greater of either 20% of the plant's gross nameplate rating, or 20 MVA).
5. We suggest combining Requirements R1 with R2, similar to other NERC Reliability Standards, in order to negate the need to have a requirement that requires an entity to document a process (R1) and another to implement that process (R2).
6. EEI notes that the SAR states that “[m]ultiple NERC disturbance reports have identified the undesired performance of bulk power system (BPS) connected inverter-based resources (IBRs) during grid faults” yet the proposed Requirement R1 would have IBR GOs capture data on any “unexpected change” on IBR power output. While a laundry list of exclusions is provided, IBR GOs will still have to capture and analyze any event that meets the criteria of R1 and determine why the drop in power output occurred and then save all of the event data except those events that meet the identified exclusions. If left unchanged this will result in a substantial new burden on IBR owners to collect and analyze significant amounts of data that in many cases will not be relatable to any system faults. Necessitating more staff and unrecoverable costs to support this effort, while not achieving the desired improvement in BPS Reliability.

While EEI offers the following as clearer language for what has been proposed for Requirement R1, we note that a Requirement such as proposed or aligned with our proposed changes will be very costly and burdensome to IBR GOs. Moreover, the only way to minimize the burden of capturing this data would be to tie these events to system disturbances, which is the root cause of IBR aberrant performance but would require GOs to have ready access to system disturbance information, which may be impractical (See proposed changes below):

R1. Each Generator Owner shall **implement one or more** documented process**(es)** to **capture and retain IBR system telemetry and IBR alarms data necessary for analyzing IBR performance during IBR or Unit IBR events where there is a decrease in Real** Power output **that is equal to or greater than 20% of the power output of the IBR or IBR Unit, but not less than 20MW,** occurring over a two-second period**. IBR and Unit IBR telemetry and alarm data captured during a specified IBR or Unit IBR event, determined by the responsible IBR GO, to have been the result of one of the following conditions negates the need for the IBR GO to retain the captured data:** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1 Losses in IBR or Unit IBR associated with weather, such as changes in wind, solar irradiance, etc.; or

1.2 Load curtailments, resource ramping, planned outages, planned resource testing; or

1.3 Loss of a transmission line connecting the IBR or Unit IBR.

To address the issue of system disturbance identification within IBR control systems, identified above, the SDT should coordinate with the Project 2021-04 (PRC-028-1) SDT to determine whether Disturbance Monitoring Equipment that will be required under that project could provide triggers into IBR control systems so that IBR Telemetry and IBR system alarms could be efficiently linked with disturbance event seen at IBR facilities. Such linkage, if feasible, would minimize IBR GO data collection, as well as provide useful information that would assist IBR GOs in understanding the impact of disturbances on their equipment while improving their ability to develop Requirement R5 CAPs that efficiently resolve performance issues.

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes

Document Name	
Comment	

Having a documented process for a performance standard is not required and is purely administrative. PRC-030 should follow PRC-004 which does not require a documented process.

The window of "occurring within a two-second period" should be modified to calculate an average of multiple power readings over a longer period.

The threshold should be described in MW instead of MVA.

The term “unexpected changes” needs more clarification and the criteria should be listed as part of the requirement instead of a footnote.

Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	

OPG supports NPCC Regional Standards Committee’s comments:

"The footnote describing what are not “unexpected changes” does not consider small (<5%) system voltages changes caused by shunt reactor or capacitor switching. This means, an IBR plant operating at constant MW (low wind conditions or vars at standstill) but regulating voltage could generate frequent (daily) “unexpected change” events by simply regulating voltage, as planned, and required.

A MW requirement instead of MVA would allow to remove all the unwanted error reporting linked to voltage regulation, especially during continuous operating conditions."

Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	

Invenergy believes additional language is needed to ensure no overlap of requirements between PRC-004-6 and PRC-030-1. Additionally, to reduce administrative burdens and better align with the language of other like standards, the documented process language should be removed and R2 should be deleted.

As currently drafted, R1 requires all data be resolute down to a 2-second or faster interval in order to accurately identify events and filter out events like those detailed in footnote 1. Not all sources of data are capable of being reported at these intervals and the proposed interval could result in inaccurate analysis, over-reporting, and data storage issues.

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC

Answer	Yes
Document Name	

Comment

Yes, TEPC agrees with EEI's comments regarding 'to identify unexpected changes' should be removed.

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3

Answer	Yes
Document Name	

Comment

Avista fully supports PRC-030 and the need to establish performance requirements for IBRs. The first ballot of the standard is a strong step in the right direction to ensure BPS reliability. We agree with EEI’s comments and support the changes suggested in those comments.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	Yes

Document Name	
Comment	

We agree with EEI's comments and support the changes suggested in those 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	Yes
Document Name	

Comment

ACES appreciates the effort put forth by the SDT in drafting the newly proposed PRC-030-1 Reliability Standard. Crafting an entirely new standard is no small undertaking and we are grateful for the hard work and dedication of the SDT members. ACES believes that draft 1 is an excellent step towards meeting the requirements of FERC Order 901; however we contend that the current language would benefit from a few modifications.

From a historical perspective, the Reliability Standards have used MVA to classify generating units and to establish a threshold for applicability. Megawatts (MW) is typically used to quantify the changes in generation output and load (e.g., Most Severe Single Contingency, Reporting ACE, EOP-004, MOD-031, CIP-002 Impact Rating, etc.). It is the opinion of ACES that it would be best for PRC-030-1 to conform to the established convention and utilize MW in lieu of MVA when identifying these event types.

Additionally, it is the opinion of ACES that the phrase "unexpected changes" is overly broad so as to capture what is arguably an edge case scenario. Per the Technical Rationale, the intent of the SDT was to:

"encompass both unexpected decreases (i.e., loss) and unexpected increases (i.e., additions) that may be caused by IBR mis-operations that could affect system reliability. For instance, a battery energy storage system that mis-measures system frequency may unexpectedly enter a charging mode."

It is our position that the greater risk to the reliability of the BES is from an unexpected decrease in generation not an unexpected increase. We do acknowledge that unexpected increases in generation may also pose a reliability risk to the BES; however, we contend that this has always been the case for all generation types and the incidence rate is statistically insignificant. Using a modified version of the example provided by the SDT in the portion of the Technical Rationale quoted above, please consider the following hypothetical scenario:

- A pumped storage hydro generating unit with a gross nameplate rating of 480 MVA is operating with an active output of 435 MW and 20 MVAR (435.5 MVA).
- During a control system malfunction event, the control system incorrectly calculated system frequency sending an incorrect frequency response signal causing the unit to exhibit a near instantaneous change in power output (note: this control action is commonly called "droop control").
  - The response to an erroneous frequency reading results in a near instantaneous change in power output to 456.75 MW and 20 MVAR (457.2 MVA).
  - The resulting change in apparent power in under 2 seconds is 21.7 MVA.
    - While this is less than 20% of the unit's gross nameplate rating, it is greater than the minimum 20 MVA threshold specified in PRC-030-1 R1.

In summary, as is illustrated in the hypothetical example above, it is our assertion that the risk to the BES from an unexpected increase of 20 MVA is immaterial to the generating resource type that caused said increase. In short, we believe that this standard should remain focused only on sudden, unexpected losses caused by IBRs at this time. We believe this approach would more closely align with PRC-004-6.

Lastly, it is ACES' opinion that the parameters identifying these types of events should be modified to more closely align with the language used in the most recent revision of EOP-004-5. Therefore, we recommend that R2 be struck in its entirety and R1 be modified to use the following language:

"Each Generator Owner that identifies an unexpected loss of aggregated Electrical Energy output at an applicable facility (per Section 4.2) shall, within 120 calendar days, determine if the unexpected loss meets the criteria identified in Part 1.1 and Part 1.2.

1.1 Occurs within a 30-second period and

1.2 Greater than either (whichever is larger):

1.2.1 20% of the IBR's Normal Rating or

1.2.2 20 megawatts (MW)"

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	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
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	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	
Document Name	
Comment	
The footnote describing what are not “unexpected changes” does not consider small (<5%) system voltages changes caused by shunt reactor or capacitor switching. This means, an IBR plant operating at constant MW (low wind conditions or vars at standstill) but regulating voltage could generate frequent (daily) “unexpected change” events by simply regulating voltage, as planned, and required. A MW requirement instead of MVA would allow to remove all the unwanted error reporting linked to voltage regulation, especially during continuous operating conditions.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Since PRC-030-1 applies to all BES and non-BES connected resources, Texas RE recommends revising section A 4.2.2 Facilities to the following: 4.2. Facilities: 4.2.1. Bulk Power Electric System (BPS BES) Inverter-Based Resources (IBR) 4.2.2. Non-Bulk Electric System (Non-BES) Inverter-Based Resources (IBR)	

This change would make PRC-030-1 consistent with PRC-028-1 and PRC-024-4 which reference BES and non-BES Inverter-Based Resources.

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
The footnote describing what are not "unexpected changes" does not consider small (<5%) system voltages changes caused by shunt reactor or capacitor switching. This means, an IBR plant operating at constant MW (low wind conditions or vars at standstill) but regulating voltage could generate frequent (daily) "unexpected change" events by simply regulating voltage, as planned, and required. A MW requirement instead of MVA would allow to remove all the unwanted error reporting linked to voltage regulation, especially during continuous operating conditions.

Likes 0	
Dislikes 0	

Response

2. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Allowing the PC or RC to lengthen the two-second period in Requirement R1 may be consistent with the objectives of the standard. There may be instances, such as weak grid or other stability needs, in which slower responses slightly beyond 2 seconds would be required. There may also be other varieties of exemptions. This may also provide a mechanism to account for documented performance characteristics that would not require analysis. This could be addressed by adding the following sentence to footnote one: "Unexpected changes would not include performance that is expected as part of documented RC-, PC-, TP-, or TOP-approved tuning or exemptions."	
Likes 0	
Dislikes 0	
Response	

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
Please see response in Question 3.	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 5, Weaver Karen
Dislikes 0	
Response	

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
The data capturing requirements are minimal in technical terms and wouldn't require the installation of additional monitoring equipment at a standard IBR installation; most of the compliance effort would be procedural and would be performed regardless by the PUD as part of its regular system disturbance analysis tasks.	

Likes 1	Snohomish County PUD No. 1, 3, Chaney Holly
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

PG&E does not have any alternatives for more cost-effective options.

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.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	No
Document Name	

Comment

Tri-State Generation and Transmission supports MRO NSRFs comment.

Likes 0	
Dislikes 0	

Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
At this time, with unclear direction of intent of responsibility, FirstEnergy cannot determine the cost effectiveness of these proposals.	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
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	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
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	
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	
It is the opinion of ACES that, as written, PRC-030-1 is not a cost-effective approach. Requiring the GO to identify any unexpected changes in power output occurring within 2 seconds will place an undue compliance burden on the GO. This is particularly true when said power output is measured in MVA. As most facilities monitor output in MW, including MVA will require the GO to either add additional monitoring capabilities or modify existing monitoring equipment to monitor an additional parameter(s). Additionally, requiring the GO to create and maintain a documented procedure as is done in R1, will increase the compliance risk of the GO with no appreciable reduction in risk to the BES. It is ACES' opinion that PRC-030-1 should be modeled after PRC-004-6 by merely requiring the GO to identify applicable event types and allowing the GO the flexibility to perform this task as it sees fit.	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
Regarding alternatives and cost-effectiveness, Invenergy has concerns that there is a significant degree of redundancy, and in some instances even conflicts, between the proposed requirements and project goals in PRC-028-1, PRC-029-1, and PRC-030-1. These projects should be aligned to ensure applicable entities do not face duplicative or conflicting requirements.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) 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 feels that there could be many alternative and more cost-effective options, so it may be prudent for the drafting team to present some alternatives addressing the FERC Order recommendations for SRP to weigh in.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
The “unexpected changes” attributed to weather patterns, change of wind and/or change in irradiance factors occur on a daily basis in some geographical regions, often multiple times per day and can easily drop the site output by 20MVA. It will be labor intensive to look at each 20MVA drop event and determine if it’s related to unexpected changes unrelated to weather factors. The more cost-effective option is to limit the evaluation to misoperations/faults and if identified by TP, PC, RC, or TO.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	

Please reference all the NAGF comments provided on this comment form for possible cost-efficiencies.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation supports the NAGF comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
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	
The source and impact of the system transients should be evaluated and remedied in addition to or rather than focusing only on the GO facility reaction to the non-normal system conditions. A reduction of or complete elimination in the source of the disturbances is in order. Any buffering or softening of the transmission system abnormal condition's impact on generating facilities, where very sensitive electronic controls are used, would improve GO facility reaction to the disturbances. Adequate transmission system voltage support equipment in weak support areas could lessen the impact of disturbances on IBR based GO facilities.	
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 North American Generator Forum (NAGF) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 2

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	

PRC-030 overlaps with PRC-029 that the SDTs should consider combining some requirements of PRC-030 into PRC-029

Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	Yes
Document Name	
Comment	

AEPC signed on to ACES comments:

It is the opinion of ACES that, as written, PRC-030-1 is not a cost-effective approach. Requiring the GO to identify any unexpected changes in power output occurring within 2 seconds will place an undue compliance burden on the GO. This is particularly true when said power output is measured in MVA. As most facilities monitor output in MW, including MVA will require the GO to either add additional monitoring capabilities or modify existing monitoring equipment to monitor an additional parameter(s). Additionally, requiring the GO to create and maintain a documented procedure as is done in R1, will increase the compliance risk of the GO with no appreciable reduction in risk to the BES. It is ACES' opinion that PRC-030-1 should be modeled after PRC-004-6 by merely requiring the GO to identify applicable event types and allowing the GO the flexibility to perform this task as it sees fit.

Likes 0	
Dislikes 0	

Response

Michael Goggin - Grid Strategies LLC - 5	
Answer	Yes
Document Name	

Comment

1. The Drafting Team should add a requirement to R3 that the TO must file its request within 15 days of the disturbance event. This will ensure that the GO has at least five days to pull data before it is overwritten, given that the data retention period in the current draft of PRC-028 R7 is 20 days.

2. In the draft, R4 and R5 specify that the GO has 45 days to complete its analysis report and then another 45 days to develop a Corrective Action Plan (CAP). This is not enough time in many cases, particularly for complex events or truly unexpected generator behavior, analysis of which is likely to present the greatest reliability value. Analyzing events in which a resource failed to ride-through a disturbance is likely to require consultation and coordination with the equipment manufacturer and project engineer, which requires significant time. Reliability would benefit if the time requirements were extended to a more reasonable period, such as 120 days for analysis and then 60 days for developing a CAP.

3. R1 and R2 could be combined and streamlined to remove the administrative and procedural requirements for having a documented process for identifying events, and instead simply require the GO to demonstrate compliance by showing that it has identified and analyzed the events it was supposed to.

Likes 0	
Dislikes 0	

Response

Patricia Ireland - DTE Energy - 4, Group Name DTE Energy	
Answer	Yes
Document Name	

Comment

The requirement to investigate each two-second 20% (or 20 MVA) drop in power output to determine if the drop meets the definition of an “unexpected change” for all NERC regulated IBRs is burdensome and, especially for very small geneating units, not cost-effective compared to the benefit derived.

We suggest incorporating into the standard a deminimus capacity rating excluding smaller generators from the scope of this standard.

Likes 0	
Dislikes 0	

Response

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes

Document Name	
Comment	
The requirement to investigate each two-second 20% (or 20 MVA) drop in power output to determine if the drop meets the definition of an “unexpected change” for all NERC regulated IBRs is burdensome and not cost-effective for any benefit derived. We suggest a deminimus capacity rating that excludes smaller contributors from the scope of this standard.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation supports NAGF comments Kimberly Turco 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	Yes
Document Name	
Comment	
As proposed, the MRO NSRF does not believe that this is cost-effective. Please see all MRO NSRF comments. Additionally, the source and impact of the system transients should be evaluated and remedied in addition to or rather than focusing only on the Generator Owner (GO) facility reaction to the non-normal system conditions. A reduction of or complete elimination in the source of the disturbances is in order. Any buffering of softening of the transmission system abnormal condition's impact on generating facilities where very sensitive electronic controls are used would improve GO facility reaction to the disturbances. Adequate transmission system voltage support equipment in weak support areas could lessen the impact of disturbances on ibr based GO facilities.	

Likes 1	Lincoln Electric System, 5, Millard Brittany
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

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	Yes
Document Name	

Comment

As described in AZPSs response to question 1 above, the Requirement as proposed will be very costly and burdensome to IBR GOs. Moreover, the only way to minimize the burden of capturing this data would be to tie these events to system disturbances, which is the root cause of IBR aberrant performance but would require GOs to have ready access to system disturbance information, which may be impractical:

To address the issue of system disturbance identification within IBR control systems, identified above, the SDT should coordinate with the Project 2021-04 (PRC-028-1) SDT to determine whether Disturbance Monitoring Equipment that will be required under that project could provide triggers into IBR control systems so that IBR Telemetry and IBR system alarms could be efficiently linked with disturbance event seen at IBR facilities. Such linkage, if feasible, would minimize IBR GO data collection, as well as provide useful information that would assist IBR GOs in understanding the impact of disturbances on their equipment while improving their ability to develop Requirement R5 CAPs that efficiently resolve performance issues.

Likes 0	
Dislikes 0	

Response

Megan Melham - Decatur Energy Center LLC - 5

Answer	Yes

Document Name	
Comment	
Please reference all the comments provided on this comment form for possible cost-efficiencies.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	
It is difficult for the industry to determine the full cost implications of PRC-030. It is premature to determine at this time the cost implications until it is fully known what is involved in the analysis of IBR loss events following grid disturbances.	
Likes 0	
Dislikes 0	
Response	
Srinivas Kappagantula - Arevon Energy - 5	
Answer	Yes
Document Name	
Comment	
Please refer to the comments provided by North American Generation Forum (NAGF) for possible cost-efficiencies.	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	

IPCO wants to highlight one of the biggest gaps not being addressed with these proposed changes: Utilities are dependent on contractors and can only hold those contractors to contractual terms. When those contractors are outside of NERC jurisdictional authority, the entities can only do some much, outside of their contracts, to make contractors comply and produce evidence. The standards and requirements must be written in ways that allow for entities to be able to comply until there is some level of authority to bring the contractors into the sphere of the NERC jurisdiction. These changes do not address that concern.

IPCO encourages improvements that encompass the parts of the relationship with the vendor or Long-Term Service Agreement administrator that the entity can control other than just through contractual means. Relying on a contractor for time-based responses presents challenges if not addressed in this draft.

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	Yes
Document Name	

Comment

WAPA isn’t a GO, however we support the MRO NSRFs feedback:

As proposed, the MRO NSRF does not believe that this cost-effective. Please see all MRO NSRF comments. Additionally, The source and impact of the system transients should be evaluated and remedied in addition to or rather than focusing only on the Generator Owner (GO) facility reaction to the non-normal system conditions. A reduction of or complete elimination in the source of the disturbances is in order. Any buffering of softening of the transmission system abnormal condition's impact on generating facilities where very sensitive electronic controls are used would improve GO facility reaction to the disturbances. Adequate transmission system voltage support equipment in weak support areas could lessen the impact of disturbances on ibr based GO facilities.

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	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	
Document Name	
Comment	
No comment. Too new and early to determine cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
no comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	
Document Name	
Comment	
TEPC agrees with EEI's comment, unkowing the outcome of this newly developed Standard, we do not have a response at this time.	
Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	
NIPSCO will not comment on cost effectiveness but please see responses to questions 1 and question 3 for recommendations.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy will not submit any input on the cost effectiveness of this newly developed Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	

Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - PNM Resources - 1,3 - WECC,Texas RE	
Answer	
Document Name	
Comment	
PNM has not researched alteratives therefore, cannot comment on more cost-effective options.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
No 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 will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	
Document Name	
Comment	
This is too broad of a question and does not pertain to PRC-030-1.	
Likes 0	
Dislikes 0	
Response	

3. Provide any additional comments for the Drafting Team to consider, if desired.

Brian Lindsey - Entergy - 1	
Answer	
Document Name	
Comment	

• Inverter-Based Resources (IBR) is capitalized but not yet defined.

• R5.2. Does not add any value.

• Propose a 5-year phased in implementation plan to give adequate time for the GO to implement effective procedures.

Likes 0	
Dislikes 0	
Response	

Mark Flanary - Midwest Reliability Organization - 10	
Answer	
Document Name	
Comment	

MRO is voting Negative on the changes to PRC-030-1 because the proposed language in R5.1 was ambiguous regarding which parts of R4 needed to be addressed in the CAP (we understand that the R5.1 CAP is intended to address both R4.1 and R4.2). This ambiguity could cause problems with enforcing R5.

Likes 0	
Dislikes 0	
Response	

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	
Document Name	
Comment	

Requirement R4: We would prefer to see 120 days which would match PRC-004 but maybe a fair compromise is 90 days. It takes time to collect all the information in some cases since it may require consulting with inverter or PPC OEMs. The requirements for notification would need to be better defined in our opinion.

Requirement R5: same comment on time as R4.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	
Document Name	

Comment

While the scope and general intent of PRC-030 appears reasonable, AEP believes its process and flow is flawed and needs to be changed. Firstly, as currently proposed, the standard process seems to include R1, R2 and R4 within 45 days of an Event which would also include cause identification. This is overly optimistic, especially in those cases where OEM support and insight will be needed, and thus it would be unreasonable to achieve this in all cases. Furthermore, R4 and R5 should both align with the PRC-004 requirements and timeframes so that both standards are consistent with one another. It is not logical to mandate "cause identification" within 45 days (or any time frame for that matter) before the root cause is even determined. While it might be reasonable to simply identify the "event" within 45 days (or 120 days to match PRC-004), additional time will still be needed to research and determine the root cause(s). This could conceivably take 45 days or more, especially if support is needed from the OEM. And once the cause is determined, at least 60 additional days (to match PRC-004) would then be needed to develop the CAP and document the Applicability (R4.2) of that CAP to other facilities. Applicability cannot be documented without first determining the root cause and then the CAP.

The standard infers that it is already "understood" that a qualifying event has occurred and been classified accordingly. As a result, there is no clear establishment of when the clock actually starts on the process.

AEP recommends that there should be a maximum time frame identified for a GO to "identify" that an "applicable Event" has occurred. The standard seems to imply that this will be done per R1/R2 within 45 days of the Event occurring or within 45 days of receiving an R3 data request. PRC-004, by contrast, allows 120 days to identify if an operation was proper, or instead, was a misoperation.

The notification obligations in R4.3 should not be handled within PRC-030, and instead, should be done as routine data requests, perhaps using the NERC Section 1600 data request process or similar.

R4.3 includes the phrase "Notification to each applicable Balancing Authority, Reliability Coordinator, *or* Transmission Operator of the analysis results." Did the SDT perhaps intend that "and" be used instead of the "or" to require that *all* of them be notified? Similarly, R5 and R6 only require the RC to be notified, and we recommend that the Balancing Authority and Transmission Operator be added to those requirements as well.

R3's data request turnaround time of "within 30 calendar days" should be changed to be twenty calendar days to align with that of R7 in PRC-028. In addition, R3 appears to be a potential double-jeopardy issue with PRC-028 R7 data requests. This is further confused by using the generic word "data" in R3. AEP requests that specificity be provided to make it clear exactly what this data *is* and is-*not*, and to specifically note it would not include data required in PRC-028. AEP would suggest going even further, ideally, by simply deleting R3 in its entirety, thereby eliminating any possibilities of double jeopardy by simultaneously violating multiple standards.

Implementation Plan: AEP has no objections for the implementation period to be six months for purposes of identification, however a separate implementation period needs to be established for those cases where field equipment changes are necessary. This is greater than simply a "configuration issue", as new equipment may be needed to obtain additional data points. AEP recommends that a period of two calendar years be allowed instead to accomplish whatever field changes may be necessary.

The requirements proposed in PRC-030 clearly and appropriately make the GO responsible for the performance of the Invertor-Based Resources and

IBR units it owns. AEP recommends the SDTs for PRC-028, PRC-029 and PRC-030 review their 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.

AEP does not believe that the Operations Planning time horizon is most appropriate for these requirements. Instead, please consider using the “Operations Assessment.”

VSLs: The row for R3 does not have an additional column or gradient related to the 30 day requirement. AEP recommends adding an additional column for cases where data is provided but done so in excess of the 30 day threshold. As a result, AEP has chosen to vote “Negative Opinion” on the non-binding poll.

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 the additional comments provided by both NAGF and EEI.

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 comments.

1. The Applicability section (A.4.2 Facilities) references BPS IBR. 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. Requirements R1 through R6 reference “Each applicable GO”. BC Hydro suggests that the use of "applicable” is redundant once the Section 4 Applicability is updated to reference Category 2 GOs.
3. Requirements R3 as drafted will obligate a GO to provide data to its BA, TOP, or RC regardless of an R1 qualified event occurring (e.g. identification of an unexpected change per R1). The Rationale for Requirement R3 section of the Technical Rationale references “allowing BAs, RCs, and TOPs flexibility to determine thresholds”. BC Hydro suggests that additional clarity is required on the “abnormal performance issues” and vis-a-vis the “thresholds” and “methods” that BAs, RCs, and TOPs may adapt to suit their specific needs as indicated in the

Technical Rationale. BC Hydro requests that the drafting team clarifies whether the intent behind R3 is to expand of scope beyond the R1 unexpected changes criteria, or to only allow the BA, TOP, or RC to obtain data on R1 events potentially missed by the GO.

4. Requirement R5 appears to assume a zero defect R1 process, i.e. any unexpected change is due to inadequate performance (e.g. misoperation), and a CAP will be necessary for each R2 event. BC Hydro requests that the drafting team provides additional clarity on this expectation as there may be other factors, extrinsic to the IBR performance against design or operational circumstances, that could potentially lead to meeting the R1 threshold and which may not warrant a CAP.
5. The timeline in Requirement R5 is expressed in “days”. BC Hydro recommends that the wording be revised to clarify whether it is business or calendar days.
6. BC Hydro recommends that the required analysis timelines be brought into alignment with PRC-004 timelines. These timelines are more reflective of the expected workload associated with obtaining and processing the IBR performance data, and there will likely be additional implementation and sustainment benefits by leveraging existing PRC-004 processes.
7. Requirement R6 Part 6.3 does not include a timeline to notify the RC(s) upon meeting a specified trigger (CAP changes or CAP completion.) Also, the Part 6.3 requirement to notify is not reflected in the VSL Table.
8. The Measures (e.g. M1, M4) include the wording: “Evidence may include, but is not limited to:” followed by an “and” enumeration. Is the intent of the drafting team to set a minimum expectation that all the numbered items must be produced as evidence of compliance, e.g. for Requirement R1 the compliance evidence must include at a minimum (1) a documented process, (2) data recordings AND (3) gross nameplate rating?
9. For Measure M1 BC Hydro suggests that “actual data recordings” may not constitute adequate evidence to substantiate the existence of a documented process, and recommends removing it.
10. 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.
11. BC Hydro recommends that the implementation plan for PRC-030-1 be coordinated with the approval of the approval of the IBR and IBR Unit definitions.

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	
Document Name	

Comment

WAPA isn’t a GO, however we support the MRO NSRFs feedback:

- §4 Applicability: Inverter-Based Resources (IBR) currently is not a defined term but is capitalized. Additionally, inverter-based resource needs to be defined prior to approval of PRC-030 to ensure consistency across NERC Reliability Standards. Furthermore, the MRO NSRF would like to know which type of Generator Owner this standard is meant to be applicable to, Category 1 GO and/or Category 2 GOP?
- Time frames in R3 & R4 do not align.
    - Within 30 days supply data for the “identified system level event” to a requestor.
    - Within 45 days GO’s must analyze “unexpected changes” that meet a threshold.
    - Generator Owner analysis timeframe shall end first then the timeframe for supplying data should begin. This would be normal/typical order of operations.
    - The MRO NSRF requests the SDT justify the timeframes chosen.
- R4.2. The MRO NSRF does not agree with this requirement as inherently assumes that there is/was an issue with how the individual generator units performed. Each I4 generation facility is unique, it should not be assumed that event conditions can be universally applied.

- R3. & R4.3. The MRO NSRF does not agree with this requirement. This is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit. Further, this data & analysis can be requested under other Standards, IRO-010-4 & TOP-003-5, the RC, TOP & BA should request this data if they believe it is necessary for the purposes of reliability.
- R5. et al. The MRO NSRF does not agree with this requirement as inherently assumes that there is/was an issue with how the individual generator units performed. The MRO NSRF does not agree with "A technical justification that addresses why corrective actions will not be applied nor implemented." This is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit. If the analysis demonstrates the equipment operated correctly, as designed and in compliance with applicable requirements then there should be no need for a Corrective Action Plan. Furthermore, there is no need to require the Corrective Action Plan to be provided to the RC as it can be requested under another Standard, IRO-010-4, the RC should request this data if they believe it is necessary for the purposes of reliability.

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

Language in R2 should be added similar to that of EOP-012-1, R7.1, to allow an explanation of why aspects of the process are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner.

However, we recommend revising PRC-004 to add the elements of this standard, rather than creating a new standard with a similar intent and different timelines. PRC-004 allows 120 days for analysis of Events; it's unclear why PRC-030 would not follow the same timeline. We recommend alignment of PRC-004 and PRC-030 timelines, as there could be overlap or revision of PRC-004 to include unexpected changes of 20% or more of IBRs in scope.

Also, most, if not all, NERC standards are applicable to the Bulk Electric System (BES). Why is this one applicable to the Bulk Power System (BPS) in Section A.4.2.1? Note that the Project Title is "Analysis and Mitigation of **BES** Inverter-Based Resource Performance Issues."

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	
Document Name	

Comment

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. 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

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	

Comment

FirstEnergy request the DT clarify a term for misoperation of an IBR so that the intent of PRC-030 is clear on intent of industry's responsibility and response.

Likes 0	
Dislikes 0	

Response

Amy Wilke - American Transmission Company, LLC - 1

Answer	
Document Name	

Comment

Comments:

1. Overall, ATC agrees that the standard is needed and is addressing an industry need.
2. Clarify if BPS IBRs is inclusive of BES IBRs

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5	
Answer	
Document Name	

Comment

R1: The language isn't clear enough. Our Wind SME interpreted it this way:

I am concerned on the 20% apparent power without any other context on facility size or technology. Example: 67 MVA with 21 2-3 MW turbines. 2-3 turbines dropping would create a self-report and investigation. In Wind, this criteria, may drive a high and maybe unnecessary level of self-reporting (or failure to self-report) and investigations.

R3 – the comment Generator Owner shall provide data – define what this request is. If they can ask for unlimited amounts of data this could become labor intensive.

R4: 4.2 – clarify the language. Is this asking for Extent of Condition or is this saying were any other sites impacted? Needs more information

R4: 4.1 - There is concern that 45 days may not be enough to complete a full root causes analysis. Request 90 days.

R5: 5.1 - Corrective Action Plan – Is cost prohibitive considered a technical justification? Need to better define constraints much like they are defined in the new EOP-012-1 language. Example: "Could not have been implemented at a reasonable cost consistent with good business practices, reliability, or safety. A cost may be deemed "unreasonable" when implementation of protection measure(s) are uneconomical to the extent that they would require prohibitively expensive modifications or significant expenditures on equipment with minimal remaining life"

Likes 0	
Dislikes 0	

Response

Srinivas Kappagantula - Arevon Energy - 5	
Answer	
Document Name	

Comment

Arevon Energy provides the following comments for additional consideration.

Section 4: Applicability 4.2 Facilities:

The approved SAR – Project Scope section states “The SAR should be applicable to all BES inverter-based resources.”. Therefore, the SDT should revisit the SAR accordingly to ensure that the SDT isnt overstepping their intended scope by including the language in Section 4.2.1. “Bulk Power System (BPS) Inverter-Based Resources (IBR)” Use of the capitalized term “Bulk Power System (BPS) Inverter-Based Resources (IBR)” should be reviewed as it is not a defined in the NERC Glossary of Terms. How can an undefined term be included in a standard? This causes ambiguity over which resources the standard would apply to.

iii. The precise scope of IBRs to be addressed under this standard need to be more clearly defined.

Requirement R2:

Arevon Energy recommends deleting the proposed Requirement R1 and revising Requirement R2 as follows:

“R2 - Each applicable Generator Operator shall identify unexpected changes in power output.”.

Requirement R3:

1. Several entities, such as, Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operator (TOP) can request the same data from the Generator Owner (GO). There is potential for duplicity/overlap by allowing multiple entities to request the same data. The BA, RC, and TOP should coordinate any data requests and have a single entity serve as the point of contact with the GO.

2. The NAGF believes that the existing TOP-003 provides the BA, RC, and TOP the ability to request data from the GOs and therefore Requirement 3 is not necessary and should be deleted.

3. Requirement R3 is not needed if analysis of a reportable event is being performed under R4 as R4.3 covers the notofication to the entities in R3.

Requirement R4:

1. The analysis of an event cannot occur unless there was a change in IBR output. Therefore, the reference to Requirement R3 is not required.

2. The timeframes for analysis appear to be much shorter than some other Reliabilty Standards, such as PRC-004 allow. A better approach would be to allow the timeframes for analysis as well as developing a CAP under R5 to align with PRC-004. That woudl be 120 days to conduct analysis and anotehr 60 days to deelop a CAP as needed. This would also ensure reporting consistency across the PRC standards.

3. Requirement 4.2 is an overreach and is at best speculative. This could also be a moot point if entities register each project as its own NCR#, for example.

Requirement R5 & R6:

1. The purpose of the Corrective Action Plan (CAP) needs to be better defined to state what it is intended to accomplish.Extending the CAP to other applicable facilities owned by the GO as mentioned previously is an overreach and speculative at best.

2. There appears to be no value in sharing the CAP with the RC and how the RC would use such information. Recommend to delete this administrative activity from R5.

3. Recommend consistency for the proposed CAP timeframe with other NERC Reliability Standards such as PRC-004.

Likes 0	
Dislikes 0	

Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
Tri-State Generation and Transmission supports MRO NSRFs comment.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	
Please see EEI comments on proposed alternative language and applicability issues	
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-030 Section 4. Applicability: 4.1 Functional Entities: 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.

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	
Document Name	2023-02_Unofficial_Comment_Form_04172024 Enel Comments - Final.docx

Comment

Enel North America Inc. (Enel) has the following comments on Draft 1 of PRC-030-1:

For Requirement R2, since Enel does not agree with Requirement R1 having a documented process, R2 should be removed.

Regarding Requirement R4.3, Enel believes that notifications to applicable Balancing Authorities, Reliability Coordinators, and Transmission Operators, place an undue burden on all parties and does not align with other performance-based standards, e.g. PRC-004-6. The same can be said for Requirement R5, Corrective Action Plan development, and Requirement R6.3, notifications if Corrective Action Plans actions or timetables change. If Reliability Coordinators deem this information necessary to monitor and assess the operation of its Reliability Coordinator Area, they may use their data specification to solicit information per IRO-010-4. The same mechanisms to retrieve data are in place for Balancing Authorities and Transmission Operators.

Additionally, in regard to development of Corrective Action Plans Enel believes that the drafted language does not allow for events where IBR generator units performed as designed. Instead, there should be specific circumstances outlined for when Corrective Action Plans are required in addition to the analysis required in Requirement R4.

Enel suggests that the SDT revisit the language in Requirement R4 to include similar language as found in PRC-004-6 R1 "…identify whether its Protection System component(s) caused a Misoperation." If the Generator Owner has identified that the unexpected change in power output is a 'misoperation' (the affected IBR did not perform as designed) then a Corrective Action Plan would be required under PRC-030 Requirement R5. In doing such, the SDT should amend PRC-030 Requirement R5.2 to "Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken" as written in PRC-004-6.

Enel supports the comments made by the MRO NSRF regarding defining IBR prior to approval and implementation of PRC-030.

Likes 0	
Dislikes 0	

Response

Megan Melham - Decatur Energy Center LLC - 5

Answer	

Document Name	
Comment	

Capital Power supports NAGF's comments.

The NAGF provides the following additional comments for consideration:

a) 4.2 Facilities:

i. The NAGF notes that the approved SAR – Project Scope section states "The SAR should be applicable to all BES inverter-based resources.". Therefore, the NAGF requests that the Drafting Team revisit the SAR accordingly to ensure that the Drafting Team is not overstepping their intended scope by including the language in Section 4.2.1. "Bulk Power System (BPS) Inverter-Based Resources (IBR)".

ii. 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.

iii. The precise scope of IBRs to be addressed under this standard need to be more clearly defined.

b) Requirement R2:

i. For the reasons stated in response to question 1, the NAGF recommends deleting the proposed Requirement R1 and revising Requirement R2 as follows:

"R2 - Each applicable Generator Operator shall implement its process to identify unexpected changes in power output.".

c) Requirement R3:

i. The NAGF is concerned with the potential for duplicity/overlap by allowing the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operator (TOP) to request data from the Generator Owner (GO). Request that the BA, RC, and TOP coordinate any data requests and have a single entity serve as the point of contact with the GO.

ii. The NAGF believes that the existing TOP-003/IRO-010 provides the BA, RC, and TOP the ability to request data from the GOs and therefore Requirement 3 is not necessary and should be deleted.

iii. Requirement R3 is not needed if analysis of a reportable event is being performed under R4.

iv. PRC-030 R3 appears to introduce a potential double jeopardy risk with PRC-028 R7. Both requirements require the GO to provide data to other registered entities. We recommend that PRC-030 R3 should be removed and R4 revised to refer to PRC-028 R7:

"PRC-030-1 R4: Each applicable Generator Owner shall analyze its IBRs performance within 45 calendar days of either the event identified pursuant to Requirement R2 or receipt of a request pursuant to PRC-028-1 R7. The analysis shall include all of the following: ".

d) Requirement R4:

i. The NAGF notes that analysis of an event cannot occur unless there was a change in IBR output. Therefore, the reference to Requirement R3 needs to be deleted. If a system level event occurs, that does necessarily mean any specific generator moved during that time period. If a generator does not move during the period in question, there is nothing to analyze however, as written, the GO must do an analysis. If the generator sees a change in output under R2, the analysis must be done. The inclusion of R3 data requests triggering an analysis is either duplicative or requiring an analysis when nothing occurred.

ii. The NAGF notes that timeframes provided in PRC-004 should be used for the proposed PRC-030 Requirement R4. The proposed 45-day time period is very short when evaluating what might be required to address an unexpected change in generation.

iii. The NAGF notes that Requirement 4.2 is an overreach/speculative and should be removed accordingly. If the DT believes this requirement to address additional resources should stay in the standard, then the due date for the analysis should be extended a minimum of 60 days per facility to be addressed.

e) Requirement R5:

i. The purpose of the Corrective Action Plan (CAP) needs to be better defined to state what it is intended to accomplish.

ii. The NAGF does not understand the value of sharing the CAP with the RC and how the RC would use such information. Recommend to delete this administrative activity from R5. In addition, if the RC wants this data, they can request it in their data specification under IRO-010.

iii. Recommend the timeframe for the proposed CAP be modified to 60 days for consistency with other NERC Reliability Standards such as PRC-004.

f) Requirement R6:

i. Remove any reference to the RC in R6. To the extent that the RC wants this data, they can request it within their data specification under IRO-010.

g) Implementation Plan

i. The implementation plan states that PRC-028 is needed to allow the proposed PRC-030 to become effective. The NAGF does not see any relationship between the requirement to have data collected at 120 readings per second and the need to evaluate output changes that occur over a two second period. The connection between these two standards needs to be explained.

h) Technical Rationale:

i. The DT mentions that the standard uses MVA instead of MW. However, the SDT does not provide any support for why the MVA value is a better measure than simply MWs. Without some support for the use of MVA and how it might provide a higher level of reliability, the NAGF cannot support the use of a more complicated measurement process.

ii. The rationale for R3 does not make sense based on Requirement R2. It appears that the DT believes that only during a system event would the IBR see this unexpected change. If that is the case, then the BA or the TOP should be expected to initiate the evaluation process, not the GO. The GO does not have wide area view/visibility into the overall electric system. If the intent is to have the GO evaluate unexpected changes in output, regardless of a system event, then R3 is not needed. In addition, TOP-003/IRO-010 allows the BA, RC or TOP to request data for their analysis. R3 is not needed to ensure that the GO provides requested data.

i) Other Concerns:

i. The NAGF notes that when PRC-030 becomes effective, we are assuming that IBR GOs will also still need to comply with PRC-004. It's not clear how PRC-030 distinguishes itself from PRC-004 in terms of applicability. We think the Applicability section 4.2 needs to be modified to cover the collector system portion of the Facility. This would depend on the new definition of IBR Unit that is being worked on under Project 2020-06. The Balance of Plant portion should still be covered under PRC-004.

ii. It is unclear how this standard relates to PRC-028 and PRC-029. Some of the high-level questions we have related to these standard and how they interact with each other include:

i. Would an "event" identified under PRC-030 be a violation of the proposed PRC-029?

ii. How is the data recorded under PRC-028 expected to impact PRC-029 and PRC-030?

iii. Would a change in output due to system conditions exceeding the "Continuous Operating Region" or the "Mandatory Operating Region" defined in PRC-029 still require an analysis and CAP under PRC-030? If so, does that mean an IBR is not allowed to cease injection for any reason under PRC-030?

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 edits to PRC-030-1:

Applicability Section Comments: EEI does not agree that the Applicability Section (4.1. Facilities) is clear. We suggest alignment with the recommendations provided by the Project 2020-06 SDT:

4.1. Facilities:

4.1.1. (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.

Requirements R2 through R6 Comments: EEI suggests the following changes to better align with other NERC Reliability Standards:

R2. Each Generator Owner shall implement its process established in Requirement R1 to identify unexpected changes in Real Power output. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

Propose deleting Requirement R3: EEI disagrees that there is a need for Requirement R3 because there are existing requirements contained within TOP-003 (for TOPs & BAs) and IRO-010 (RCs) that allow these registered entities to obtain this data by simply including the data within their data specifications.

Requirement R4 Proposed Changes: Under PRC-004, responsible entities have 120 days to conduct their analysis of equipment misoperations. At a minimum, the same amount of time is required for IBR GOs to assess aberrant performance of IBRs, noting the analysis of IBR performance is more complex requiring the involvement of vendors and OEMs to fully assess the reasons and possible solutions. Additionally, Requirement R4, subpart 4.3 is unnecessary noting that responsible BAs, RCs, and TOPs can obtain the results of entity analysis through TOP-003 and IRO-010 data specifications.

R4. Each applicable Generator Owner shall analyze its IBRs performance within 120 calendar days of either the event identified pursuant to Requirement R2 or receipt of a request pursuant to Requirement R3. The analysis shall include all of the following: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

4.1. The cause(s) of unexpected change(s) in power output;

4.2. The applicability to its other IBR facilities that could be affected by the same cause of unexpected change(s) in power output; and

Requirement R5 Proposed Changes: Under PRC-004, responsible entities are provided 60 days from the completion of their analysis to the development of a CAP. GOs should be provided the same amount of time.

R5. Generator Owner shall, within 60 days of completing the analysis in Requirement R4, develop one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. A Corrective Action Plan (CAP) for the identified Inverter Based Resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R4 Part 4.2; or

4.2. A technical justification that addresses why corrective actions will not be applied nor implemented.

Requirement R6 Proposed Changes: Requirement R6, subpart 6.3 should be deleted. There are no similar requirements within PRC-004 and RC reporting requirements are not needed within PRC-030-1.

R6. Each Generator Owner shall, for each of its CAPs developed pursuant to Requirement R5: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

6.1. Implement the CAP;

6.2. Update the CAP if actions or timetables change; and

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	
Document Name	

Comment	
As Requirement R5 is the twin requirement of PRC-004 Requirement R5, we suggest using bullets instead of sub-requirements so that the text to both requirements is harmonized and is read the same way. 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 2020-04 (PRC-028) and 2020-02(PRC-029). Section 4.2.1 refers to BPS IBRs, however it is our understanding that section 4. 1.1 would refer to GOs “that own equipment as identified in section 4.2.1” and where section 4.2.1 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.”	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
Requirement R4 will require a rapid event detection and analysis process to abnormal events by all registered IBR owners. Related to the rapid timeframes associated with R4, some additional clarification for Requirement R4.2 is needed. Within the 45 days of an identified event, a GO may be challenged to also identify the applicability of the root cause problem to all its other IBR facilities. Does this applicability work include all owned IBRs across every BA/RC/TOP footprint it operates in, just neighboring IBRs close to the where the event occurred, or is it a system risk mitigation across all similar IBR make/models installed on the entire BPS? This is very critical work to be performed to maintain Bulk Power System reliability but requiring that this analysis occur within 45 days of the system event appears to be a significant burden that may not result in the adequate system risk mitigation that is intended. Rather than putting this applicability work in Requirement R4.2 within the first 45 days, we give the recommendation to remove	

Requirement R4.2 and place this applicability work into Requirement R5, creating a new R5.2 that mirrors Requirement R4.2 while also requiring a CAP to be implemented for each applicable facility identified in the new R5.2.

For Requirement R5, does the CAP allow the GO to express an open-ended timeline for corrective actions, such as working with the OEM to address an identified change? It is highly unlikely that GOs will have solved the underlying performance issue within a 45-day window (e.g., coordinating with the OEM). Therefore, it is highly likely that most CAPs will involve a defined/known timeline to work with the OEM to resolve the root cause issues. Those timelines are likely hard to predict or unknown within the 45-day timeline due to challenges that GOs may have coordinating with OEMs (particularly for older inverters). Given that Requirement R6.2 allows for the updating of the CAP as timelines change, it appears this unpredictable time for OEMs to solve some root cause issues will be updated and tracked as part of R6.2. Yet we felt this point of long and unpredictable CAP timelines an important point to highlight to ensure the realities of Requirement R5 and R6 for some root cause issues are understood and thought through.

For Requirement R5 and R6, we also believe there may need to be specific callouts in the CAP language regarding updates to the IBR models following root cause event analysis, establishing reasonable timelines and deadlines on the post-event model validation effort. This may touch on the 2025 standards updates regarding Order 901 and should be coordinated early to ensure alignment and minimize the potential re-work. While getting fixes implemented in the field to address the root cause problems is essential, equally important is getting updated models (steady-state, dynamic, EMT model, etc.) with the root cause mitigations included, where applicable, so that the TP/PC have the most accurate, up-to-date IBR models that match what is in the field. Reasonability needs to be given in terms of model validation timelines due to the need to coordinate with the OEM in many cases.

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	
Document Name	

Comment

Currently there are multiple standards projects in draft including development of IBR and IBR unit defined terms. With this amount of focus and new requirements for IBRs, entities should be given additional time to implement new processes and programs for applicable facilities. A 12 month implementation period would greatly support the success of new IBR compliance programs.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	MRO-NSRF_2023-02-PRC-030_UCF_04-17-2024_FINAL.docx

Comment

The MRO NSRF provides the following feedback:

- §4 Applicability: Inverter-Based Resources (IBR) currently is not a defined term but is capitalized. Additionally, inverter-based resource needs to be defined prior to approval of PRC-030 to ensure consistency across NERC Reliability Standards. Furthermore, the MRO NSRF would like to know which type of Generator Owner this standard is meant to be applicable to, Category 1 GO and/or Category 2 GOP? The MRO NSRF suggests: 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.
- Time frames in R3 & R4 do not align.

o Within 30 days supply data for the "identified system level event" to a requestor.

o Within 45 days GO's must analyze "unexpected changes" that meet a threshold.

o Generator Owner analysis timeframe shall end first then the timeframe for supplying data should begin. This would be normal/typical order of operations.

o The MRO NSRF requests the SDT justify the timeframes chosen. Perhaps aligning with the timeframes of PRC-004-6 is a better option?

- R4.2. The MRO NSRF does not agree with this requirement as inherently assumes that there is/was an issue with how the individual generator units performed. Each I4 generation facility is unique, it should not be assumed that event conditions can be universally applied.
- R3. & R4.3. The MRO NSRF does not agree with this requirement. This is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit. Further, this data & analysis can be requested under other Standards, IRO-010-4 & TOP-003-5, the RC, TOP & BA should request this data if they believe it is necessary for the purposes of reliability.
- MRO NSRF suggests removing 4.3 and 6.3 entirely as they are solely administrative in nature.
- R5. et al. The MRO NSRF does not agree with this requirement as inherently assumes that there is/was an issue with how the individual generator units performed. The MRO NSRF does not agree with "A technical justification that addresses why corrective actions will not be applied nor implemented." This is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit. If the analysis demonstrates the equipment operated correctly, as designed and in compliance with applicable requirements then there should be no need for a Corrective Action Plan. Furthermore, there is no need to require the Corrective Action Plan to be provided to the RC as it can be requested under another Standard, IRO-010-4, the RC should request this data if they believe it is necessary for the purposes of reliability.

Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Exelon supports the suggested additional edits proposed in the EEI comments for this question.

Likes 0	
Dislikes 0	

Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

BPA agrees with R3, as it would allow the BA or TOP to request data regarding disturbances from IBR GOs.

Addtionally, BPA seeks clarity if the TP was considered for notification in R5 and R6, as well as the RC? BPA believes there could potentially be differences in IBR behavior in planning studies due to changes in IBRs driven by CAPs required in PRC-030.

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	

PG&E supports the NAGF additional comments for consideration:

a) Requirement R4:

i. The NAGF notes that timeframes provided per PRC-004 should be considered for the proposed PRC-030 Requirement R4 to ensure reporting consistency across the PRC standards.

b) Requirement R5:

i. The NAGF does not understand the value of sharing the CAP with the RC and how the RC would use such information. Recommend to delete this administrative activity activity from R5.

ii. Recommend consistency for the proposed CAP timeframe with other NERC Reliability Standards such as PRC-004.

Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Scott Thompson - PNM Resources - 1,3 - WECC,Texas RE

Answer	
Document Name	

Comment

PNM agrees with EEI's comments. In addition, Inverter-Based Resources (IBR) must be in the NERC glossary of terms before PNM can support the implementation plan and standard PRC-030-1

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment

Constellation supports NAGF comments and further adds: • “Nameplate rating” needs to be clarified as they are many ways to define that especially for solar and storage plant. Recommend revising that to “ 20% of the plant’s real power rating at the Point of Interconnection as defined in the interconnection agreement.” • SDT needs to re-assess the need for R3 as there is overlap with R4. If an entity complies R4, there would be no need for R3. • Analysis completion of IBR performance associated with R4 timeframe needs to be adjusted to 120 days to match PRC-004 . 45 days is not reasonable.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5

Answer	
Document Name	

Comment

R3/R5:

· The 45-day time frame in PRC-030-1 R3, to investigate and determine the cause of an unexpected change is reasonable for straightforward events but is not adequate in a situation when an in-depth analysis is required (particularly if the analysis must be performed by a contracted firm). This timeframe should be modified to align with the 120-day investigation timeline in PRC-004-6 R3.

· Similarly, development of a corrective action may be straight forward or complex, requiring contracted services difficult to procure in a timely manner. We suggest that the PRC-030-1 R5 timeline requirement of 45-days be amended to align with the PRC-004-6 R5 (60-days).

Implementation Plan:

We currently do not have alarming capabilities to identify unexpected changes for IBRs in real-time. We request that the implementation plan include an enforcement date that provides adequate time to implement this newly required detective control and its associated training and documentation.

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

In the technical justification document, some discussion of how the 2s time relates to recent high-profile events is warranted. From reading those reports it was not clear how those events related to the choice of 2s.

Likes 0	
Dislikes 0	

Response

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Patricia Ireland - DTE Energy - 4, Group Name DTE Energy

Answer	
Document Name	

Comment

R3/R5:

The 45-day time frame in PRC-030-1 R3, to investigate and determine the cause of an unexpected change is reasonable for straightforward events but is not adequate in a situation when an in-depth analysis is required (particularly if the analysis must be performed by a contracted firm). This timeframe should be modified to align with the 120-day investigation timeline in PRC-004-6 R3.

Similarly, development of a corrective action may be straight forward or complex, requiring contracted services difficult to procure in a timely manner. We suggest that the PRC-030-1 R5 timeline requirement of 45-days be amended to align with the PRC-004-6 R5 (60-days).

Implementation Plan:

We currently do not have alarming capabilities to identify unexpected changes for IBRs in real-time. We request that the implementation plan include an enforcement date that provides adequate time to implement this newly required detective control and its associated training and documentation.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	
Document Name	

Comment

- R4/R5: During a system-level event the IBR output could change by more than 20% of its MVA rating as a result of voltage change, instantaneous voltage positive phase angle change, or frequency change at the high side of the IBR main transformer. SDT may need to clarify that the analysis should investigate if the change of the IBR output meets the PRC-029 ride-through requirements. The Corrective Action Plan (CAP) could be required if the IBR response does not meet ride-through requirements.
- MH suggests that adding 4.4 "to the IBR change meets the ride-through requirements.
- MH suggests that this project should be aligned with Project 2020-02 (PRC-029).

- We recommend modifying Section 4 of PRC-030-1 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.

- 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-030 should be aligned with Project 2021-04 (PRC-028-1) for the legacy IBRs.

- MH suggests 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 2020-02 (PRC-029). MH 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.

- Time frames in R3 & R4 do not align.

1. Within 30 days supply data for the "identified system level event" to a requestor.
2. Within 45 days GO's must analyze "unexpected changes" that meet a threshold.
3. Generator Owner analysis timeframe shall end first then the timeframe for supplying data should begin. This would be a normal/typical order of operations.
4. The MH requests the SDT justify the timeframes chosen. Perhaps aligning with the timeframes of PRC-004-6 is a better option?

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	
Document Name	

Comment

AEPC signed on to ACES comments:

- Section 4 of PRC-030-1 draft 1 includes all Bulk-Power System IBRs; however, this is not in line with the Project Scope as defined in the SAR:

“The SAR should be applicable to all BES inverter-based resources.”

While we understand the time constraints placed upon the SDT by FERC Order 901, we would prefer to follow NERC’s established processes by modifying the SAR in the event of a scope change.

- Furthermore, we are concerned that as written, this Reliability Standard overlaps with the requirements of PRC-004-6. It is our recommendation that this standard be modified so as to specifically exclude any components already included under PRC-004-6 . In short, it is our opinion that PRC-030-1 should only apply to those event types not covered by PRC-004-6.

Thus, ACES recommends the following changes to Section 4:

- 4.1 Functional Entities:
  - 4.1.1 Generator Owner (GO)
- 4.2 Facilities:
  - 4.2.1 Inverter-Based Resource (IBR) meeting the registration criteria for either a Category 1 or Category 2 GO, with the following exclusions:

4.2.1.1 Protection Systems
4.2.1.2 Special Protection Systems (SPS)
4.2.1.3 Remedial Action Schemes (RAS)
4.2.1.4 Underfrequency Load Shedding (UFLS) that is intended to trip one or more BES Elements
4.2.1.5 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

- Additionally, we at ACES have concerns with the timelines specified in Requirements R3 and R4. Requiring the GO to collect data and analyze an event within 30 calendar days and 45 calendar days respectively is much more stringent than identifying and analyzing similar event types under PRC-004-6 Requirements R1, R2, and R3 (i.e., 120 calendar days). We believe these shortened timelines are overly burdensome to the GO and should be aligned with PRC-004-6.
- Moreover, Requirement R3 does not apply any constraints for how long the BA, RC, or TO have to request the data from the GO. Is the GO expected to store and maintain all data for all applicable IBRs for an indefinite period of time? As the BA, RC, and TO already have the ability to request data from the GO under Reliability Standards IRO-010 and TOP-003, we recommend that Requirement R3 and Requirement Part 4.3 be struck from PRC-030-1.
- Lastly, it is the opinion of ACES that Requirement R5 should be modified such that it only applies when an issue is identified after performing the analysis required by R4. We recommend the following language:

“Each Generator Owner that identifies a performance issue under Requirement R4 shall, within 45 days of completing the analysis, develop a Corrective Action Plan (CAP) for correcting the identified issue. The CAP shall include other applicable facilities owned by the Generator Owner as identified in Requirement R4 Part 4.2 that utilize the same equipment that caused the performance issue.

Thank you for the opportunity to comment.

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

Applicability for PRC-030 should align with PRC-028 and PRC-029

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	
Document Name	

Comment

1 In R1 “plant gross nameplate” is unclear and needs to be better defined, if we have multiple registered generators interconnecting to the same POI are they to be considered separately?

2 There appears to be duplication between PRC-030 R3 and PRC-028 R7, both require GOs to provide data requested by BA/RC/TOP within 30 calendar days. This could introduce double jeopardy and is not necessary, we suggest that PRC-030 R3 is removed. TOP-003 provides further ability for BA/RC/TOPs to request this data.

3 Determining applicability to other IBR facilities under R4.2 is not feasible within 45 calendar days for all cases at larger GOs. We suggest this sub-requirement be granted a more flexible or longer duration timeline with 90 days at minimum. Note that similar requirements in PRC-004 are set to 60 days at the shortest.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5

Answer	
Document Name	

Comment	
As Requirement R5 is the twin requirement of PRC-004 Requirement R5, we suggest using bullets instead of sub-requirements so that the text to both requirements is harmonized and is read the same way. 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 2020-04 (PRC-028) and 2020-02(PRC-029). Section 4.2.1 refers to BPS IBRs, however it is our understanding that section 4. 1.1 would refer to GOs “that own equipment as identified in section 4.2.1” and where section 4.2.1 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.”	
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), North American Generator Forum (NAGF), and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3	
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	
In the applicability section, the precise scope of IBRs needs to be clearly defined rather than stating "GOs with BPS IBRs". For R3, the request to the GO for data (which must be delivered within 30 calendar days of the request) needs to be required to be made (by the requesting party) within a reasonable time frame after the event occurrence. The GO should not be required to retain all recorded event data ad infinitum.	

It seems plausible that a "system level event" (R3) may or may not involve every IBR facility. In the cases where no power output change occurred, the subparts of the analysis listed in the subparts of R4 are not applicable. This should be formally recognized in the requirement.

R3 altogether and the part of R4 referencing R3 (…or receipt of a request pursuant to Requirement R3.) are not needed and should be removed. An event which causes an unexpected change in the power output is called upon to be examined (R4) and delivered to the interested parties (R4.3) elsewhere in this draft standard. If a system event occurs where a specific IBR does not have a unexpected change in power output, there is no analysis to be done, no need to deliver results to other interested parties, and no need to assume those administrative duties to simply indicate that no unexpected change in power output occurred. What is the reliability benefit for administrative actions enumerated in R4?

The analysis specified in R4 can be duplicative of analysis required within the current draft of PRC-029. There should not be duplicative requirements (double jeopardy) in multiple standards.

Is R4.3 meant to have the GO provide the results to the requesting party? As written, the GO has a choice as to which of the three parties listed may be sent the results.

The timeframes provided per PRC-004 should be considered for the proposed PRC-030 Requirement R4 to ensure reporting consistency across the PRC standards.

R5, as written, does not make it clear why a CAP is to be developed. What is the purpose of the CAP?

R5, as written, implies that a GO may have multiple RCs to report to - need to reword to "… to its RC" rather than "… to each applicable RC".

Events involving existing IBR facilities, in-service before the effective date of PRC-030 and the implementation plan date of PRC-028 (1/1/2030) may not have DME with recording capability for performing a detailed analysis. The implementation plan for existing units should be delayed until PRC-028 requires DME at those locations (1/1/2030).

Events involving the Protection System equipment that result in a required investigation to determine if the Protection System correctly operated due to PRC-004 should be exempt from requiring a duplicate analysis with reporting for PRC-030.

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 has the following additional comments for the Standards Drafting Team (SDT) to consider. First, the Applicability section in the proposed PRC-030-1 states: “4.2 Facilities: 4.2.1. Bulk Power System (BPS) Inverter-Based Resources (IBR).”

This language is too broad and would include *all* IBRs interconnected to the Bulk Power System at *any* voltage level. To appropriately reduce the scope of PRC-030-1, the SDT should consider the language proposed in NERC Standards Project 2021-04 Modifications to PRC-002 - Phase II, PRC-028-1 draft #2, which states:

"4.1. Functional Entities:

4.1.1. Generator Owner *that owns equipment as identified in section 4.2* [emphasis added]

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."

Lastly, in Requirement R3, the term "system level event" is not defined. SDT should consider defining this term, or consider other similar changes, so that an IBR owner can be requested to analyze its IBR performance for power system oscillations that do not meet the "20% of the plant's gross nameplate rating, or 20 MVA" criteria in Requirement R1, upon a request from its BA, RC or TOP. This would ensure that IBR Generator Owners are accountable to helping resolve power oscillations in which the IBR's performance may be a contributing factor.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation supports the NAGF comments and further adds:

- "Nameplate rating" needs to be clarified as they are many ways to define that especially for solar and storage plant. Recommend revising that to " 20% of the plant's real power rating at the Point of Interconnection as defined in the interconnection agreement."
- SDT needs to re-assess the need for R3 as there is overlap with R4. If an entity complies R4, there would be no need for R3.
- Analysis completion of IBR performance associated with R4 timeframe needs to be adjusted to 120 days to match PRC-004 . 45 days is not reasonable.

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	
Document Name	

Comment

The NAGF provides the following additional comments for consideration:

a) 4.2 Facilities:

i. The NAGF notes that the approved SAR – Project Scope section states "The SAR should be applicable to all BES inverter-based resources.". Therefore, the NAGF requests that the Drafting Team revisit the SAR accordingly to ensure that the Drafting Team is not overstepping their intended scope by including the language in Section 4.2.1. "Bulk Power System (BPS) Inverter-Based Resources (IBR)".

ii. 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.

iii. The precise scope of IBRs to be addressed under this standard need to be more clearly defined.

b) Requirement R2:

i. For the reasons stated in response to question 1, the NAGF recommends deleting the proposed Requirement R1 and revising Requirement R2 as follows:

"R2 - Each applicable Generator Operator shall implement its process to identify unexpected changes in power output.".

c) Requirement R3:

i. The NAGF is concerned with the potential for duplicity/overlap by allowing the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operator (TOP) to request data from the Generator Owner (GO). Request that the BA, RC, and TOP coordinate any data requests and have a single entity serve as the point of contact with the GO.

ii. The NAGF believes that the existing TOP-003/IRO-010 provides the BA, RC, and TOP the ability to request data from the GOs and therefore Requirement 3 is not necessary and should be deleted.

iii. Requirement R3 is not needed if analysis of a reportable event is being performed under R4.

iv. PRC-030 R3 appears to introduce a potential double jeopardy risk with PRC-028 R7. Both requirements require the GO to provide data to other registered entities. We recommend that PRC-030 R3 should be removed and R4 revised to refer to PRC-028 R7:

"PRC-030-1 R4: Each applicable Generator Owner shall analyze its IBRs performance within 45 calendar days of either the event identified pursuant to Requirement R2 or receipt of a request pursuant to PRC-028-1 R7. The analysis shall include all of the following: ".

d) Requirement R4:

i. The NAGF notes that analysis of an event cannot occur unless there was a change in IBR output. Therefore, the reference to Requirement R3 needs to be deleted. If a system level event occurs, that does necessarily mean any specific generator moved during that time period. If a generator does not move during the period in question, there is nothing to analyze however, as written, the GO must do an analysis. If the generator sees a change in output under R2, the analysis must be done. The inclusion of R3 data requests triggering an analysis is either duplicative or requiring an analysis when nothing occurred.

ii. The NAGF notes that timeframes provided in PRC-004 should be used for the proposed PRC-030 Requirement R4. The proposed 45-day time period is very short when evaluating what might be required to address an unexpected change in generation.

iii. The NAGF notes that Requirement 4.2 will be addressed under Requirement R5 and it is an overreach/speculative. Therefore, Requirement R4.2 should be removed accordingly. If the DT believes this requirement to address additional resources should stay in the standard, then the due date for the analysis should be extended a minimum of 60 days per facility to be addressed.

iv. Requirement R4.3 should require submittal to TOP, not RC and BA. GOs with many sites will have increased administrative burdens from such reporting activities.

e) Requirement R5:

i. The purpose of the Corrective Action Plan (CAP) needs to be better defined to state what it is intended to accomplish.

ii. The NAGF does not understand the value of sharing the CAP with the RC and how the RC would use such information. Recommend to delete this administrative activity from R5. In addition, if the RC wants this data, they can request it in their data specification under IRO-010.

iii. Recommend the timeframe for the proposed CAP be modified to 60 days for consistency with other NERC Reliability Standards such as PRC-004.

f) Requirement R6:

i. Remove any reference to the RC in R6. To the extent that the RC wants this data, they can request it within their data specification under IRO-010.

g) Implementation Plan

i. The implementation plan states that PRC-028 is needed to allow the proposed PRC-030 to become effective. The NAGF does not see any relationship between the requirement to have data collected at 120 readings per second and the need to evaluate output changes that occur over a two second period. The connection between these two standards needs to be explained.

h) Technical Rationale:

i. The DT mentions that the standard uses MVA instead of MW. However, the SDT does not provide any support for why the MVA value is a better measure than simply MWs. Without some support for the use of MVA and how it might provide a higher level of reliability, the NAGF cannot support the use of a more complicated measurement process.

ii. The rationale for R3 does not make sense based on Requirement R2. It appears that the DT believes that only during a system event would the IBR see this unexpected change. If that is the case, then the BA or the TOP should be expected to initiate the evaluation process, not the GO. The GO does not have wide area view/visibility into the overall electric system. If the intent is to have the GO evaluate unexpected changes in output, regardless of a system event, then R3 is not needed. In addition, TOP-003/IRO-010 allows the BA, RC or TOP to request data for their analysis. R3 is not needed to ensure that the GO provides requested data.

i) Other Concerns:

i. The NAGF notes that when PRC-030 becomes effective, we are assuming that IBR GOs will also still need to comply with PRC-004. It's not clear how PRC-030 distinguishes itself from PRC-004 in terms of applicability. We think the Applicability section 4.2 needs to be modified to cover the collector system portion of the Facility. This would depend on the new definition of IBR Unit that is being worked on under Project 2020-06. The Balance of Plant portion should still be covered under PRC-004.

ii. It is unclear how this standard relates to PRC-028 and PRC-029. Some of the high-level questions we have related to these standard and how they interact with each other include:

i. Would an "event" identified under PRC-030 be a violation of the proposed PRC-029?

ii. How is the data recorded under PRC-028 expected to impact PRC-029 and PRC-030?

iii. Would a change in output due to system conditions exceeding the "Continuous Operating Region" or the "Mandatory Operating Region" defined in PRC-029 still require an analysis and CAP under PRC-030? If so, does that mean an IBR is not allowed to cease injection for any reason under PRC-030?

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE recommends including a time period for identifying unexpected changes in power output occurring within a two-second period in accordance with Requirement R1. The GO should have a specific process for identifying the unexpected changes in power output event within specific period to capture these occurrences. Without specific time period, many of the unexpected changes in power output may go unidentified. This could also make it difficult to audit the standard requirement if the entity did not identify any unexpected changes in power output that may have occurred. Texas RE recommends the following revision:

R2. Each applicable Generator Owner shall implement its process established in Requirement R1 to identify unexpected changes in power output **within 30 calendar days of the unexpected change in power output occurred.**

Since Requirements R3 and R4 include a timeline for the GO providing data when requested and the GO analyzing its IBRs' performance, Texas RE recommends including that in the VSLs for Requirements R3 and R4.

Likes 0	
Dislikes 0	

Response

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1

Answer	
Document Name	

Comment

This standard is problematic in that it is one of several that are all being enacted piece meal to satisfy the FERC Order. It would be better to have them all together. As currently written, how can a BA request the data if the IBR output is via a Purchased Power Agreement (PPA) only. The IBR is not yet a Generator Owner.

R3 enables the BA, RC, or TOP to request the data that the GO is purportedly being able to provide, but there is no “oversite” of the GO’s process.

R3 contradicts R4. R4 gives the GO 45 days to analyze the IBR performance, but R3 requires the results to be provided within 30 days of the request. If the data requested from the GO in R3 (within 30 days of request) is different from the analysis requested in R4 (within 45 days of request), then the types of data required by R3 should be specified (or at least an example provided).

R5/R6. There is no specificity in how long the initial CAP can be set. If the plan is to fix them over the next 20 years, no updates would ever be required. There is no mechanism for the BA, RC, or TOP to hold the GO to hurry things along or follow “good engineering principles”.

Compliance section 1.2 R4 bullet: a reference is made to a “declaration”. Where does it state that any declaration needs to be made. What declaration is being referred to here?

Likes 1	Tallahassee Electric (City of Tallahassee, FL), 5, Weaver Karen
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

Duke Energy suggests the implementation of the following Duke Energy, EEI and NAGF review comments. Duke Energy EEI and NAGF comment modifications are bracketed by asterisks.

EEI COMMENTS

EEI offers the following additional edits to PRC-030-1:

Applicability Section Comments: EEI does not agree that the Applicability Section (4.1. Facilities) is clear. We suggest alignment with the recommendations provided by the Project 2020-06 SDT (See boldface changes below):

4.1. Facilities:

4.1.1. (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 kV.

Requirements R2 through R6 Comments: EEI suggests the following changes to better align with other NERC Reliability Standards:

R2. Each Generator Owner shall implement its process established in Requirement R1 to identify unexpected changes in **Real Power** output. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

Propose deleting Requirement R3: EEI disagrees that there is a need for Requirement R3 because there are existing requirements contained within TOP-003 (for TOPs & BAs) and IRO-010 (RCs) that allow these registered entities to obtain this data by simply including the data within their data specifications.

R3. DELETE

Requirement R4 Proposed Changes: Under PRC-004, responsible entities have 120 days to conduct their analysis of equipment misoperations. At a minimum, the same amount of time is required for IBR GOs to assess aberrant performance of IBRs, noting the analysis of IBR performance is more complex requiring the involvement of vendors and OEMs to fully assess the reasons and possible solutions. Additionally, Requirement R4, subpart 4.3 is unnecessary noting that responsible BAs, RCs, and TOPs can obtain the results of entity analysis through TOP-003 and IRO-010 data specifications. (see changes in boldface below)

R4. Each applicable Generator Owner shall analyze its IBRs performance within **120** calendar days of either the event identified pursuant to Requirement R2 or receipt of a request pursuant to Requirement R3. The analysis shall include all of the following: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

4.1. The cause(s) of unexpected change(s) in power output;

4.2. The applicability to its other IBR facilities that could be affected by the same cause of unexpected change(s) in power output; and

4.3. DELETE

Requirement R5 Proposed Changes: Under PRC-004, responsible entities are provided 60 days from the completion of their analysis to the development of a CAP. GOs should be provided the same amount of time.

R5. Generator Owner shall, within **60** days of completing the analysis in Requirement R4, develop one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. A Corrective Action Plan (CAP) for the identified Inverter Based Resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R4 Part 4.2; or

4.2. A technical justification that addresses why corrective actions will not be applied nor implemented.

Requirement R6 Proposed Changes: Requirement R6, subpart 6.3 should be deleted. There are no similar requirements within PRC-004 and RC reporting requirements are not needed within PRC-030-1.

R6. Each Generator Owner shall, for each of its CAPs developed pursuant to Requirement R5: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

6.1. Implement the CAP;

6.2. Update the CAP if actions or timetables change; and

6.3. **DELETE**

NAGF COMMENTS

The NAGF provides the following additional comments for consideration:

a) 4.2 Facilities:

i. The NAGF notes that the approved SAR – Project Scope section states "The SAR should be applicable to all BES inverter-based resources.". Therefore, the NAGF requests that the Drafting Team revisit the SAR accordingly to ensure that the Drafting Team is not overstepping their intended scope by including the language in Section 4.2.1. "Bulk Power System (BPS) Inverter-Based Resources (IBR)".

ii. Use of the capitalized term "Bulk Power System (BPS) Inverter-Based Resources (IBR)" should be reviewed as it is not a defined in the NERC Glossary of Terms.

iii. The precise scope of IBRs to be addressed under this standard need to be more clearly defined.

b) Requirement R2:

i. The NAGF recommends deleting the proposed Requirement R1 and revising Requirement R2 as follows:

"R2 - Each applicable Generator Operator shall implement its process to identify unexpected changes in power output.".

c) Requirement R3:

i. The NAGF is concerned with the potential for duplicity/overlap by allowing the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operator (TOP) to request data from the Generator Owner (GO). Request that the BA, RC, and TOP coordinate any data requests and have a single entity serve as the point of contact with the GO.

ii. The NAGF believes that the existing TOP-003 provides the BA, RC, and TOP the ability to request data from the GOs and therefore Requirement 3 is not necessary and should be deleted.

iii. Requirement R3 is not needed if analysis of a reportable event is being performed under R4.

d) Requirement R4:

i. The NAGF notes that analysis of an event cannot occur unless there was a change in IBR output. Therefore, the reference to Requirement R3 needs to be deleted.

ii. The NAGF notes that timeframes provided per PRC-004 should be considered for the proposed PRC-030 Requirement R4 to ensure reporting consistency across the PRC standards.

iii. The NAGF notes that Requirement 4.2 is an overreach/speculative and should be removed accordingly. *****R4.2 is already included in R5 and should be removed. During the CAP, the GOP will determine if the problem applies to other sites.*****

iv. *****R4.3 should require submittal to TOP, not RC and BA. GOs with many sites will have increased administrative burdens for reporting activities.*****

e) Requirement R5:

i. The purpose of the Corrective Action Plan (CAP) needs to be better defined to state what it is intended to accomplish.

ii. The NAGF does not understand the value of sharing the CAP with the RC and how the RC would use such information. Recommend to delete this administrative activity from R5.

iii. Recommend consistency for the proposed CAP timeframe with other NERC Reliability Standards such as PRC-004.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	
Document Name	

Comment

R2. - This is an unnecessary requirement as it is not in alignment with other performance analysis standards. It should be removed.

R3. - This requirement seems to be redundant to PRC-028, requirement R7. It should be removed.

R4. - The requirement needs to define that only misoperations/faults need to be analyzed.

R5. - The requirement needs to be revised to state that CAP is not needed if IBR reacted as designed.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	
Document Name	

Comment

WECC suggests that the

SDT should consider the definition of Inverter-Based Resource being developed. As is, the “Facilities” section is not consistent with other Standards being developed. Additionally, Inverter-Based Resource should be used instead of “plant” in R1. Consider the use of IBR or Inverter-Based Resource for consistency throughout Standard (e.g., R3/R4 uses IBR, R4 additionally uses IBR facilities, R5 uses Inverter-Based Resource and R1 uses plant).

The Technical Rationale description “system level event” is accurate but may limit a BA/RC/TOP approach to IBRs response review. Project 2023-01 limits loss to MWs (current ≥ 500 MW) which is different from the expected response review criteria as explained in the Technical Rational. Voltage collapse scenarios can be localized and IBR responses would need to be reviewed to understand the reasons (and mitigate future risk of re-occurrence).

WECC believes GOs should analyze performance of Inverter-Based Resources if the criteria is met in R1 without needing a system level event to be identified.

Providing the analysis of the response to the RC, BA, and TOP but only providing the CAP to the RC leaves a gap in reliability for the BA. How does planning (TP or PC) receive the response analysis information or the CAP actions that may impact planning models?

Technical Rationale mentions “acceptable” technical justification expectations that could essentially negate mitigation of risk. Since this Standard is around “unexpected” occurrences, interconnection requirements may need to be updated to mitigate risks (see multiple event reports regarding Inverter-Based Resource losses). Allowing a GO to provide that technical justification may cause entities to take no action which does not support reliable operations. Suggest dropping “material modification” as the term was removed from FAC -002 Standard and replaced with “qualified change”. FAC-002 should be considered by the GOs and a “qualified change” that impacts reliability should not go unresolved. As is, there is no language regarding approval of the CAP or any specific maximum time limit for a CAP which implies an operational risk could go unresolved for an indefinite period. WECC appreciates the “operating restrictions” comments in the Technical Rationale but system conditions (or the political environment) may not allow a BA/RC/TOP to implement those restrictions (assuming including disconnecting the Inverter-Based Resource).

The applicability sectioin indicates that this standard is limited to BPS Inverter-Based Resources. WECC interpprets this to be excluding non-BPS Inverter Based Resources? As non-BES Inverter-Based Resources proliferate, performance may need reviewed and should be considered.

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

As Requirement R5 is the twin requirement of PRC-004 Requirement R5, we suggest using bullets instead of sub-requirements so that the text to both requirements is harmonized and is read the same way.

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 2020-04 (PRC-028) and 2020-02(PRC-029). Section 4.2.1 refers to BPS IBRs, however it is our understanding that section 4. 1.1 would refer to GOs “that own equipment as identified in section 4.2.1” and where section 4.2.1 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.”

Likes 0	

Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	
Document Name	
Comment	
Exelon supports the suggested additional edits proposed in the EEI comments for this question.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
The language in Requirement R3 should be restructured to clarify that the BA, RC, or TOP may require the GO to initiate and perform analysis related to System-level events, which is the intent of this requirement. Additionally, the requirement to provide "data" when requested should be expanded to also require the provision of "information" when requested. As reflected in recent changes made to IRO-010 and TOP-003, the term "information" encompasses more than just data (e.g. PMU/DFR/DDR/SCADA data) and may include settings, OEM documentation, unit parameters, etc.	

The SDT should ensure that the timelines in Requirement R4 are consistent with the timelines used for the Event Analysis program. If 45 calendar days are needed for an R4 analysis, then the SDT should coordinate with the Event Analysis Subcommittee (EAS) to coordinate the Event Analysis program timelines as needed.

Under Requirement R5.1, the CAP should, if possible, use the IBR and IBR Unit definitions that are being developed in Project 2020-06, both to ensure consistency and to clarify that the CAP may at times not be for the entire plant but for individual turbines or inverters. Based on the responses provided during the Project 2020-02 webinar, ERCOT is concerned that this SDT may be assuming the Project 2020-02 SDT is addressing the issue of partial reductions in output (IBR unit trips/abnormal reduction) not being allowed, while the Project 2020-02 SDT may be assuming this SDT is addressing that topic. Regardless of which SDT ultimately addresses the topic, the two SDTs should work together to ensure consistency among their respective standards and to ensure that the standards clearly provide that partial reductions in output (IBR unit trips/abnormal reductions) would constitute a performance failure even if the entire plant does not trip.

Requirement R5.2 inappropriately allows GOs to avoid implementing corrective actions without receiving an assessment of the resulting reliability impact or any sort of oversight or pre-approval. If, consistent with FERC Order 901, planners and coordinators must take System-level actions to address the reliability impacts of exemptions or performance failures (the mitigation of which may take months or even years to implement without a firm requirement on timeliness), leaving corrective actions unimplemented at the IBR or IBR Unit level may create a reliability gap until System-level mitigations are implemented (if System changes can even practically resolve the reliability impact, which is not certain). Unmitigated ride-through performance failures can, in aggregate, have an impact that triggers UVLS, UFLS, Cascading outages, instability, and uncontrolled separation.

Requirement R6 should include language that requires the CAP to be implemented as soon as practicable and no later than a specific deadline (e.g., 90 days) unless otherwise approved by the RC. Otherwise, CAPs could take years to implement or never be implemented at all. While ERCOT agrees that, as described in the Technical Rationale, one way of mitigating this risk is to impose operating restrictions that incentivize timely CAP implementation, it would be better to address this issue in the Requirement instead of in the Technical Rationale. This is especially important since NERC has prioritized planner and operator requirement changes ordered in FERC Order 901 after the initial wave of projects, and these two issues are explicitly linked (operating restrictions may be needed to address reliability risks that arise from exemptions or unmitigated performance failures). Assuming that future projects will address this issue does not adequately or timely address this reliability risk; consequently, this issue should be addressed in this standard, especially given that some Generator Owners continue to dispute RC authority to impose operating restrictions.

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 edits to PRC-030-1:

Applicability Section Comments: EEI does not agree that the Applicability Section (4.1. Facilities) is clear. We suggest alignment with the recommendations provided by the Project 2020-06 SDT (See proposed changes below):

4.1. Facilities:

4.1.1. (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.

Requirements R2 through R6 Comments: EEI suggests the following changes to better align with other NERC Reliability Standards:

Propose combining Requirement R2 with R1: See EEI's justification within our response to question 1.

Propose deleting Requirement R3: EEI disagrees that there is a need for Requirement R3 because there are existing requirements contained within TOP-003 (for TOPs & BAs) and IRO-010 (RCs) that allow these registered entities to obtain this data by simply including the data within their data specifications.

Requirement R4 Proposed Changes: Under PRC-004, responsible entities have 120 days to conduct their analysis of equipment misoperations. At a minimum, the same amount of time is required for IBR GOs to assess aberrant performance of IBRs, noting the analysis of IBR performance is more complex requiring the involvement of vendors and OEMs to fully assess the reasons and possible solutions. Additionally, Requirement R4, subpart 4.3 is unnecessary noting that responsible BAs, RCs, and TOPs can obtain the results of entity analysis through TOP-003 and IRO-010 data specifications. (See proposed changes below)

R4. Each applicable Generator Owner shall analyze its IBRs performance within **120** calendar days of either the event identified pursuant to Requirement R2 or receipt of a request pursuant to Requirement R3. The analysis shall include all of the following: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

4.1. The cause(s) of unexpected change(s) in power output;

4.2. The applicability to its other IBR facilities that could be affected by the same cause of unexpected change(s) in power output; and

Requirement R5 Proposed Changes: Under PRC-004, responsible entities are provided 60 days from the completion of their analysis to the development of a CAP. GOs should be provided the same amount of time. (see proposed changes below)

R5. Generator Owner shall, within **60** days of completing the analysis in Requirement R4, develop one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1 A Corrective Action Plan (CAP) for the identified Inverter Based Resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R4 Part 4.2; or

5.2 A technical justification that addresses why corrective actions will not be applied nor implemented.

Requirement R6 Proposed Changes: Requirement R6, subpart 6.3 should be deleted.   There are no similar requirements within PRC-004 and RC reporting requirements are not needed within PRC-030-1. (see proposed changes below)

R6. Each Generator Owner shall, for each of its CAPs developed pursuant to Requirement R5: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

6.1. Implement the CAP;

6.2. Update the CAP if actions or timetables change; and

Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	

The period to analyze IBR performance within 45 calendar days should be increased to 120 days to match PRC-004 and allow time to determine the root cause especially if OEM support is required.

NIPSCO also recommends that the SDTs for PRC-028, PRC-029, and PRC-030 review their proposed standards to ensure there is a consistent plan to achieve the goal of correcting IBR performance issues.

The period to develop CAP should be within 60 calendar days instead of 45 days to align with PRC-004.

The notification in R4.3 is confusing as written, “to each applicable Balancing Authority, Reliability Coordinator, or Transmission Operator”, is the notification suppose to be to all listed, in which case the “or” should be “and”.

The implementation period of six months would be adequate for the purpose of identification, but if equipment changes or upgrades are needed to comply the period should be increased to 2 years to allow for these changes or upgrades.

Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	

OPG supports NPCC Regional Standards Committee's comments:

"As Requirement R5 is the twin requirement of PRC-004 Requirement R5, we suggest using bullets instead of sub-requirements so that the text to both requirements is harmonized and is read the same way.

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 2020-04 (PRC-028) and 2020-02(PRC-029). Section 4.2.1 refers to BPS IBRs, however it is our understanding that section 4. 1.1 would refer to GOs "that own equipment as identified in section 4.2.1" and where section 4.2.1 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.""

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.

The Applicability section would benefit from alignment with the other IBR-focused standards in development. As currently drafted, PRC-028-1, PRC-029-1, and PRC-030-1 all use different language to describe the same applicable Facilities.

Regarding the timeline in requirement R4, 45 days is not enough time for sufficient analysis. In almost all cases, evaluation and analysis will need to be supported by IBR OEMs, and it is not guaranteed that resources exist to provide feedback that quickly.

Likes 0	
Dislikes 0	
Response	

Dave Krueger - SERC Reliability Corporation - 10	
Answer	

Document Name	
Comment	

On behalf of the SERC Generator Working Group:

Applicability section: Is the intent to capture the new Category 2? Suggest defining more precisely. Also, has BPS been used before it defining facilities?

For R4.3, we suggest eliminating R3 altogether along with the reference to R3 in R4 because the residual part of the requirement will achieve delivering the analysis of any unexpected output change to the parties of R3. If no change was detected at the plant, no analysis was required, and no reporting should be necessary. (and the request that may come from R3 would yield nothing more than an acknowledgment of no change detected, which is of no value).

Likes 0	
Dislikes 0	
Response	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC

Answer	
Document Name	
Comment	

TEPC agrees with EEI comments to revise Section 4.1 Facilities, combining requirement 1-2, deleting requirement 3 to remove duplication of efforts, and revising requirements 4-5 the number of days for analysis.

Likes 0	
Dislikes 0	
Response	

John Pearson - ISO New England, Inc. - 2

Answer	
Document Name	
Comment	

• The timelines in R3 and R4 don’t seem to make sense and appear to contradict. If there’s a system level event, does this specify that there are 30 or 45 days to respond?

• In any case, either 30 or 45 days is a very long period of time to analyze unexpected changes in generator power output . We believe that it could and should be done within 5 to 7 business days. It’s likely part of a larger investigation that would take weeks to do AFTER receiving the IBR information. Within 30 days there should be a final report (not 45 days) per R4. Given the information that these installations have access to, providing the information in 5 to 7 business days should be reasonable.

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3

Answer	
Document Name	

Comment

Avista agrees with EEI's comments

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	
Document Name	

Comment

We fully support PRC-030 and the need to establish performance requirements for IBRs. The first ballot of the standard is a strong step in the right direction to ensure BPS reliability. We agree with EEI's comments and support the changes suggested in those 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

- Section 4 of PRC-030-1 draft 1 includes all Bulk-Power System IBRs; however, this is not in line with the Project Scope as defined in the SAR:

“The SAR should apply to all BES inverter-based resources.”

While we understand the time constraints placed upon the SDT by FERC Order 901, we would prefer to follow NERC’s established processes by modifying the SAR in the event of a scope change.

- Furthermore, we are concerned that as written, this Reliability Standard overlaps with the requirements of PRC-004-6. We recommend that this standard be modified to specifically exclude any components already included under PRC-004-6 . In short, it is our opinion that PRC-030-1 should only apply to those event types not covered by PRC-004-6.

Thus, ACES recommends the following changes to Section 4:

4.1 Functional Entities:

4.1.1 Generator Owner (GO)

4.2 Facilities:

4.2.1 Inverter-Based Resource (IBR) meeting the registration criteria for either a Category 1 or Category 2 GO , with the following exclusions:

4.2.1.1 Protection Systems

4.2.1.2 Special Protection Systems (SPS)

4.2.1.3 Remedial Action Schemes (RAS)

4.2.1.4 Underfrequency Load Shedding (UFLS) that is intended to trip one or more BES Elements

4.2.1.5 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

- Additionally, we at ACES have concerns with the timelines specified in Requirements R3 and R4. Requiring the GO to collect data and analyze an event within 30 calendar days and 45 calendar days respectively is much more stringent than identifying and analyzing similar event types under PRC-004-6 Requirements R1, R2, and R3 (i.e., 120 calendar days). We believe these shortened timelines are overly burdensome to the GO and should be aligned with PRC-004-6.
- Moreover, Requirement R3 does not apply any constraints for how long the BA, RC, or TO have to request the data from the GO. Is the GO expected to store and maintain all data for all applicable IBRs for an indefinite period of time? As the BA, RC, and TO already have the ability to request data from the GO under Reliability Standards IRO-010 and TOP-003, we recommend that Requirement R3 and Requirement Part 4.3 be struck from PRC-030-1.
- Lastly, it is the opinion of ACES that Requirement R5 should be modified such that it only applies when an issue is identified after performing the analysis required by R4. We recommend the following language:

“Each Generator Owner that identifies a performance issue under Requirement R4 shall, within 45 days of completing the analysis, develop a Corrective Action Plan (CAP) for correcting the identified issue. The CAP shall include other applicable facilities owned by the Generator Owner as identified in Requirement R4 Part 4.2 that utilize the same equipment that caused the performance issue."

Thank you for the opportunity to comment.

ODEC has the following additional comments:

- In ODEC's opinion, adding additional PRC Reliability Standards that are similar to existing standards creates uncertainty and confusion as to which standards apply to which resource types. We recommend either creating a new category or subcategory of named "IBR" specific standards. Please see the following 2 different examples of potential updates to the NERC Standards Numbering System:

- New Topic Area
  - IBR-001-1
- New sub-category
  - PRC-004-IBR-1

- ODEC believes that either PRC-004 or PRC-030 should apply to IBRs, but not both. We recommend exempting IBRs from PRC-004 and incorporating any applicable PRC-004-6 requirements into PRC-030-1.

Likes 0	
Dislikes 0	

Response

Consideration of Comments

Project Name:	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues | Draft 1
Comment Period Start Date:	3/25/2024
Comment Period End Date:	4/18/2024
Associated Ballot(s):	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Implementation Plan IN 1 OT 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues PRC-030-1 IN 1 ST

There were 66 sets of responses, including comments from approximately 180 different people from approximately 120 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. Does the entity believe there should be proposed changes in language in regards to Requirement R1 “to identify unexpected changes”?

2. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

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
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
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
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
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

					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	SERC
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Scott Berry	Wabash Valley Power Association	3	RF
					Sara Orr	Golden Spread Electric Cooperative, Inc.	5	Texas RE
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC

					Jolly Hayden	East Texas Electric Cooperative, Inc.	NA - Not Applicable	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 Corporation	6	RF
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			Micah Runner	Black Hills Corporation	1	WECC

				Black Hills Corporation - All Segments	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	1	NPCC

	Edison Co. of New York		
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
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
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	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 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 Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri	3	SERC

						Electric Power Cooperative		
					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. Does the entity believe there should be proposed changes in language in regards to Requirement R1 “to identify unexpected changes”?	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	

WAPA isn’t a GO, however we support the MRO NSRFs feedback:

- Need to ensure that PRC-030 R1 does not include balance of plant (BOP) Protection System already covered under PRC-004-6. An example would be PV & wind generation 34.5kV collection system Protection Systems. This should be addressed in the §4. Applicability as follows “4.2.1. the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.”
- The threshold should simply be a magnitude e.g. 20MVA. Anything less than 20MVA would not affect the Bulk Electrical System pursuant to the definition and is the accepted threshold within industry. This would also more closely align with GADS Event reporting thresholds. In addition, the MRO NSRF would like to understand the justification of why apparent power is the magnitude being used by the SDT?
- 2 second time period. The MRO NSRF does not agree with the rationale for 2s time period “The two second time period, the fastest Supervisory Control and Data Acquisition (SCADA) scanning rate…”. The MRO NSRF suggests “within one-minute” time period. The time period shall start when the first individual generating unit is lost. This aligns with the time-frame traditionally used and this ensures that the events that need to be analyzed are captured without having multiple events or over analysis.

Alternative:

- 2 second time period. The MRO NSRF does not agree with the rationale for 2s time period “The two second time period, the fastest Supervisory Control and Data Acquisition (SCADA) scanning rate…”. The MRO NSRF suggests “within 30 seconds” time period. The time period shall start when the first individual generating unit (ibr) is lost. The MRO NSRF suggests reviewing Project 2023-01 EOP-004 IBR Event Reporting, Technical Rationale document for EOP-004-5.

- The MRO NSRF does not agree with Requirement R2 “documented process to identify unexpected changes”. Generator Owners need to analyze “unexpected changes” that meet a threshold. Having a process is unnecessary, not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit.

Likes 0	
Dislikes 0	

Response

Please see MRO response. The EOP-004 time period is extended to allow for delays in SCADA coming from multiple facilities as well as the delay to roll up all IBR telemetry into a single calculation. Individual unit telemetry does not require this additional time unless multiple units within the facility are being rolled up into plant level monitoring. The DT will consider extended possibly up to 10 seconds.

Sean Steffensen - IDACORP - Idaho Power Company - 1

Answer	No
Document Name	

Comment

On the surface, this seems like a reasonable standard to produce practices surrounding event archiving and heighten reliability from the IBR resources. IBR resources are still in their adolescence and their event interactions with the system are not well understood or foreseen at this time. This raises questions about the timing of these changes. There are also questions surrounding the financial solvency of the current IBR market. Will the market still look the same in 5-10 years? How will these changes impact a market that looks completely different a few years from now?

IPCO strongly encourages NERC to find a way to better address the relationship with the vendor, or Long-Term Service Agreement Administrator, to ensure that the entity is only held responsible for those things that is within their control in this process. IPCO understands this is a challenging process to navigate but encourage NERC to draft the standard in a way that recognizes and allows flexibility around time frames dictated in PRC-030.

Likes 0	
Dislikes 0	

Response

Thank you for the comment, the Drafting Team is working to build a standard that best supports grid reliability as the IBR market continues to grow. The time frames have been extended to account for this in the revised standard.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see EEI response.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State Generation and Transmission supports MRO NSRFs comment.	
Likes 0	
Dislikes 0	
Response	
Please see MRO response.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	

Answer	No
Document Name	
Comment	

AZPS supports that following comments that were submitted by EEI on behalf of its members:

EEI does not support the proposed language in Requirement R1 due to the following concerns:

1. The use of the term "unexpected changes" adds ambiguity and subjectivity to the requirement and should be removed.

2. The use of footnotes places clarifying information outside of the requirement and should be brought directly into Requirement R1.

3. We suggest replacing "power" with Real Power in order to align with the NERC defined term.

4. EEI asks that the SDT provide some justification for the proposed event trigger (i.e., greater of either 20% of the plant's gross nameplate rating, and at least 20 MVA).

5. We suggest combining Requirements R1 with R2, similar to other NERC Reliability Standards, in order to negate the need to have a requirement that requires an entity to document a process (R1) and another to implement that process (R2).

6. EEI notes that the SAR states that "[m]ultiple NERC disturbance reports have identified the undesired performance of bulk power system (BPS) connected inverter-based resources (IBRs) during grid faults" yet the proposed Requirement R1 would have IBR GOs capture data on any "unexpected change" on IBR power output. While a laundry list of exclusions is provided, IBR GOs will still have to capture and analyze any event that meets the criteria of R1 and determine why the drop in power output occurred and then save all of the event data except those events that meet the identified exclusions. If left unchanged this will result in a substantial new burden on IBR owners to collect and analyze significant amounts of data that in many cases will not be relatable to any system faults. Necessitating more staff and unrecoverable costs to support this effort, while not achieving the desired improvement in BPS Reliability.

While EEI offers the following as clearer language for what has been proposed for Requirement R1, we note that a Requirement such as proposed or aligned with our proposed changes will be very costly and burdensome to IBR GOs. Moreover, the only way to minimize the burden of capturing this data would be to tie these events to system disturbances, which is the root cause of IBR aberrant performance but would require GOs to have ready access to system disturbance information, which may be impractical:

R1. Each Generator Owner shall implement one or more documented process(es) to capture and retain IBR system telemetry and IBR alarms data necessary for analyzing IBR performance during IBR or Unit IBR events where there is a decrease in Real Power output that is equal to or greater than 20% of the power output of the IBR or IBR Unit, but not less than 20MW, occurring over a two-second period. IBR and Unit IBR telemetry and alarm data captured during a specified IBR or Unit IBR event, determined by the responsible IBR GO, to have been the result of one of the following conditions negates the need for the IBR GO to retain the captured data: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1 Losses in IBR or Unit IBR associated with weather, such as changes in wind, solar irradiance, etc.; or

1.2 Load curtailments, resource ramping, planned outages, planned resource testing; or

1.3 Loss of a transmission line connecting the IBR or Unit IBR.

To address the issue of system disturbance identification within IBR control systems, identified above, the SDT should coordinate with the Project 2021-04 (PRC-028-1) SDT to determine whether Disturbance Monitoring Equipment that will be required under that project could provide triggers into IBR control systems so that IBR Telemetry and IBR system alarms could be efficiently linked with disturbance event seen at IBR facilities. Such linkage, if feasible, would minimize IBR GO data collection, as well as provide useful information that would assist IBR GOs in understanding the impact of disturbances on their equipment while improving their ability to develop Requirement R5 CAPs that efficiently resolve performance issues.

Likes 0	
Dislikes 0	
Response	

Please see EEI response.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
The list provided in the Footnote (1) of the Standard for unexpected power output changes is pretty exhaustive and I can't think of anything to add to it.	
Likes 1	Snohomish County PUD No. 1, 3, Chaney Holly
Dislikes 0	
Response	
Thank you for the comment.	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) agrees with the proposed language in Requirement 1 and doesn't believe there should be changes.	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Patricia Ireland - DTE Energy - 4, Group Name DTE Energy	

Answer	No
Document Name	
Comment	

The language in R1 of the standard related to the definition of unexpected changes is clear. However, the “two-second” period requires additional definition before we can implement appropriate detective controls. We assume that this time period refers to two-second intervals rather than any two-second span, or is this up to each entity to determine? We would appreciate clarification prior to submittal for board approval.

Likes 0	
Dislikes 0	

Response

Thank you for the comment, this time frame refers to any time span.

Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	
Comment	

The power output change monitored should be MW rather than MVA. System voltage transient conditions may drive the reactive output temporarily up or down in exceedance of the criteria thresholds, and monitoring of this regulation response is not the object of this standard drafting effort. All previous system disturbance response evaluations performed by NERC have focused on the MW loss from facilities due to disturbances. The event evaluations prescribed by this draft standard should also focus on unexpected MW changes.

Southern Company recommends that R1 be eliminated and R2 be modified to include the specifics of the process found in R1 in the R2 requirement to implement a process to identify unexpected changes.

The 2-second time frame is quicker than most EMS SCADA polling rates. The EMS SCADA data could miss an event that is longer than two (2) sec, but shorter than the EMS scan rate. Was this time frame selected to not include events where the IBR plant returns to the pre-disturbance condition in less than two (2) seconds?	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, MVA has been replaced by MW in the revised standard. Requirement R1 to have a documented process has been combined with the execution. The two second time frame has been extended to four seconds in the revised standard.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
Please see response in Question 3.	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 5, Weaver Karen
Dislikes 0	
Response	
Please see response to Tallahassee Electric Question three.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy suggests the implementation of the following Duke Energy, EEI and NAGF review comments. Duke Energy EEI and NAGF comment modifications are bracketed by asterisks.

EEI COMMENTS

EEI does not support the proposed language in Requirement R1 due to the following concerns:

1. The use of the term "unexpected changes" adds ambiguity and subjectivity to the requirement and should be removed.

2. The use of footnotes places clarifying information outside of the requirement and should be brought directly into Requirement R1.

3. We suggest replacing "power" with Real Power to align with the NERC defined term.

4. EEI asks that the SDT provide some justification for the proposed event trigger (i.e., greater of either 20% of the plant's gross nameplate rating, or 20 MVA). *****Suggest using 20 MW or 20 MVAr as threshold event triggers, instead of the stated 20% of the plant's gross nameplate rating or 20 MVA triggers.*****

5. EEI notes that the SAR states that "[m]ultiple NERC disturbance reports have identified the undesired performance of bulk power system (BPS) connected inverter-based resources (IBRs) during grid faults" yet the proposed Requirement R1 would have IBR GOs capture data on any "unexpected change" on IBR power output. While a laundry list of exclusions is provided, IBR GOs will still have to capture and analyze any event that meets the criteria of R1 and determine why the drop in power output occurred and then save all of the event data except those events that meet the identified exclusions. If left unchanged this will result in a substantial new burden on IBR owners to collect and analyze significant amounts of data that in many cases will not be relatable to any system faults. Necessitating more staff and unrecoverable costs to support this effort, while not achieving the desired improvement in BPS Reliability.

While EEI offers the following as clearer language for what has been proposed for Requirement R1, we note that a Requirement such as proposed or aligned with our proposed changes will be very costly and burdensome to IBR GOs. Moreover, the only way to minimize the burden of capturing this data would be to tie these events to system disturbances, which is the root cause of IBR aberrant performance but would require GOs to have ready access to system disturbance information, which seems impractical:

R1. Each Generator Owner shall have a documented process to **capture and retain IBR system telemetry and IBR alarms data necessary for analyzing IBR performance during IBR or Unit IBR events where there is a decrease in Real** Power output **that is equal to or greater than 20% of the power output of the IBR or IBR Unit, but not less than 20MW,** occurring over a two-second period**. IBR and Unit IBR telemetry and alarm data captured during a specified IBR or Unit IBR event, determined by the responsible IBR GO, to have been the result of one of the following conditions negates the need for the IBR GO to retain the captured data:** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1 Losses in IBR or Unit IBR associated with weather, such as changes in wind, solar irradiance, etc.; or

1.2 Load curtailments, resource ramping, planned outages, planned resource testing; or

1.3 Loss of a transmission line connecting the IBR or Unit IBR.

An alternative solution to the above would be to link the capture of IBR telemetry and system alarms to system disturbance events as identified within the Disturbance Monitoring Equipment that will be required at IBR facilities under Project 2021-04 (PRC-028-1). It is EEI's understanding that output triggers could be programmed within this equipment to directly tie drops in Real Power output to system disturbances. This would significantly reduce the requirement for data capture within PRC-030-1.

NAGF COMMENTS

The NAGF does not support the proposed language for Requirement R1 and provides the following comments for consideration:

a. The 2 second timeframe to identify unexpected changes in power output may not be possible for existing inverter-based resource (IBR) facilities. *****It's also our opinion that events which recover within the 2 second timeframe should not require assessment. GOs with large fleets having to assess every response which falls into the 2 second timeframe would result in an enormous effort to review.*****

b. The NAGF requests that the 20MVA threshold be revised to reference MW *****or MVAr***** instead of MVA. c. The NAGF notes that PRC-004: Protection System Misoperation Identification and Correction does not require a documented process to identify misoperations, rather it requires applicable registered entities to identify misoperations and take actions accordingly. Therefore, the NAGF recommends that the proposed PRC-030 Requirement R1 be deleted or modified to align with PRC-004. d. The NAGF notes that Requirement R1 "shall have a documented process" is purely an administrative documentation effort that provides no benefit to reliability. Note that Paragraph 81 efforts eliminated such administrative burdens from the NERC Reliability Standards and as such the DT should not be including such administrative activities in the proposed PRC-030. e. Recommend moving footnote #1 – unexpected changes in output criteria as items listed under Requirement R1. f. The NAGF notes that the process and activities proposed under Requirement R1 and R2 better aligns with Generator Operator (GOP) responsibilities rather than Generator Owner (GO).	
Likes 0	
Dislikes 0	
Response	
Please see EEI response and NAGF response.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
On behalf of the SERC Generator Working Group: Suggest eliminating requirement to develop a process and change the threshold levels found in R1 and include that in R2. For R1, suggest changing to MW from MVA so an event isn't triggered on normal voltage swings	
Likes 0	

Dislikes 0	
Response	
Please see MRO response. The DT changed language in Requirement R1 to reflect the change from MVA to MW.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment.	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
• PRC-004-6 already covers balance of plant (BOP) Protection System disturbances, so some distinction needs to be provided to direct activities to be completed under PRC-004 and those to be completed under this standard. • The disturbance threshold should be described in MW, not MVA (20MW not 20 MVA). o Additional cost to calculate MVA that our controllers do not currently perform. • The 2-second time period is too short. Most SCADA systems in North America utilize a 2-second or slower scan time. Therefore, it is quite conceivable that events might not be captured with the current SCADA configuration. If the situation rights itself in 2-seconds, then it probably does not need to be studied. o Any calculations that are required to be added to determine MVA would further increase the time period and make the proposed 2 second time period too fast. o The disturbance time period should be more like one minute and should commence with the loss of the first generating unit. If it is a genuine issue, then it will last for 60 seconds.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the Drafting Team’s response:	

1. The DT has considered the overlap between PRC-004 and PRC-030-1 and felt there was no need for adjustments to the PRC-004 standard. 2. The standard language in Requirement R1 has changed to reflect MW instead of MVA. 3. The two second period has been changed to up to four seconds. 4. Thank you for the idea, the DT will take it into consideration when drafting the new standard.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
In general Vistra agrees with Entergy's comments. We believe the wording is too ambiguous and we would like to see more guidance provided on the expected process. It would help to add more specifics, i.e. "if there is a power output drop during a system disturbance that does not return to pre disturbance levels." We agree that PRC-004-6 already covers most of the collector substation so perhaps PRC-029 should only cover the IBR units? 2 seconds may be too short and the SCADA justification is weak, 30 to 60 seconds may be more be more reasonable.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the Drafting Team's response: 1. Guidance to be provided in Technical Rationale 2. GO would not know if their unit's drop in output was related to system disturbance. 3. PRC-004 focuses on Misoperation. If protection systems are set to trip unnecessarily this would not be covered in PRC-004 so it needs to be included in PRC-030. 4. The two second period was meant to detect events in which there was a sudden drop in output. If the time period is extended it would include more ramping type events related to the exclusions listed in Requirement R1. DT will consider extended possibly up to 10 seconds.	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP recommends footnote 1 be modified to indicate that unexpected changes in power are calculated as the change from the average of multiple power readings for a period of greater than or equal to 0.1 second.	
Likes 0	
Dislikes 0	
Response	
Please see ACES response.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation supports the NAGF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment please see the responses to NAGF and EEI comments.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes

Document Name	
Comment	
BC Hydro appreciates the drafting team's efforts and the opportunity to comment, and offers the following comments. BC Hydro suggests that additional clarification may be beneficial on scenarios that could constitute an 'expected change'. A transmission line outage may obfuscate situations where IBRs output unexpectedly drops prior to the line trip, e.g. some Type 4 machines use technology to allow for negative sequence contribution. For a scenario where a windfarm with this technology that doesn't provide negative sequence current during a connecting transmission outage and subsequent transmission line trip – would this be considered an 'unexpected change in generator output' or an 'expected change in generator output'?	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, Footnote 1 has been merged into Requirement 1 and new language has been used to attempt to clarify.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Clarify what the "loss of a Transmission Line connecting the IBR generator" refers to. Does it only refer to the generator lead line? Does it only cover if a generator is on a radial transmission line? The loss of either the generator lead line or a radial transmission line connecting the IBR would result in the disconnection of the IBR and not create any unexpected changes. If the IBR is connected to more than one transmission line, the IBR should not have unexpected changes. An IBR generator should respond to system topology changes as expected through offline studies. Strengthen the standard by expanding R1 to cover events that the RC or TOP identify. This allows for multiple entities to identify events. Also, the RC or TOP can request data from the GO for events (R3) and the GO needs to analyze events pursuant to R3 (R4).	

Using the gross nameplate rating for a threshold could miss events from large IBRs that are operating at a low output. Change the threshold to be 20% of pre-event MW output.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the Drafting Team has made changes to Requirement R1 in bring in the footnote into the Requirement, along with adding clarifying language to the standard. Thank you for the suggestions the DT will take these into account when drafting the new standard.	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Generation is typically measured in MW not MVA	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, MVA has been replaced by MW in the revised standard.	
Srinivas Kappagantula - Arevon Energy - 5	
Answer	Yes
Document Name	
Comment	

Arevon Energy does not support the proposed language for Requirement R1 and provides the following comments for consideration:

1. The 2 second timeframe to identify unexpected changes in power output may not be possible for exiting inverter-based resource (IBR) facilities. The 2 second timeframe is too short. Morst SCADA systems utilize a 2-seconr or slower scan time. Hence, most events might not even be captured within the current SCADA configurations. If the situation rights itself in 2-seconds, then it probably doesnt require to be studied.

2. The disturbance threshold should be described in MW not MVA, most plant owners/operators deal in MW not necessarily talk about a plant in MVA.

3. PRC-004-6 already covers balance of plant (BOP) equipment and related Protection System disturbances. There needs to be some distinction between the activities that need to be performed under PRC-004 and those that this standard is proposing to be studided.

4. R1 is purely administrative in nature and of no reliability benefit. Having a documented process for a performance standard isnt required. Paragraph 81 efforts eliminated such administrative burdens from the NERC Reliability Standards and as such the SDT should not be including such administrative activities in the proposed PRC-030. A good example is PRC-004, which does not require a documented process to identify misoperations, rather it requires applicable registered entities to identify misoperations and take actions accordingly. PRC-030 should align with the approach PRC-004 takes. Essentially delete R1 and make R2 a requirement to identify the unexpected changes in power output.

5. The term "unexpected changes" needs more clarification. While the footnote provides some context, it does not provide enough clarification. For example, the footnote does not include faults. Is the expectation that the GO would document each time the plant reacts to a fault? Arevon Energy recommends removing the footnote and including the criteria under R1 as a list to avoid any ambiguity. The SDT shoudl focus on what should be included in "unexpected changes" rather than simply listing exclusions.

6. The process and activities proposed under Requirement R1 and R2 may better align with Generator Operator (GOP) responsibilities rather than Generator Owner (GO).

Likes 0	
Dislikes 0	

Response	
Thank you for the comment, 1. The two-second time frame has been extended to four seconds in the revised standard. 2. MVA has been replaced by MW in the revised standard. 3. PRC-004-6 is focused on misoperation of protective elements while PRC-030-1 is focused on IBR generation loss. 4. The requirement to have a documented process has been combined with the execution. 5. Footnote one has been merged into Requirement R1 6. The Drafting Team feels that the Generator Owner is ultimately responsible for the performance of the unit.	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	
Enel North America Inc. (Enel) would like to thank the Standard Drafting Team for their efforts in developing this reliability standard. Enel does not agree with the language in Requirement R1 for the following reasons: First, a documented process is not necessary for compliance and does not align with similar standards, e.g. PRC-004-6. Enel believes that a documented process for this standard is administrative in nature, does not support reliability, and is needlessly burdensome (NERC's "Paragraph 81" criteria as set forth in 138 FERC ¶ 61,193 at P81 (2012)). Second, regarding the time-period to identify an applicable event, Enel believes that the two-second period is too short. The technical rationale for the time-period is arbitrary and based on hardware capability rather than industry-accepted standards that establish a minimum scanning rate. Such a short time-period would necessitate storing large amounts of data, i.e. large volume of discrete data points, to be kept for upwards of 45 days, accounting for currently drafted analysis requirements, Requirement R4. Enel would suggest the SDT provide further justification to support the time-period that is reflective of events experienced by IBRs, e.g. Odessa or leverage established industry standards. Third, the 20 MVA threshold should be changed to align with GADS Event reporting, loss of at least of 20MW of Plant Total Installed Capacity.	

Likes 0	
Dislikes 0	

Response

Thank you for the comment the DT response:
1. DT believes a documented process is necessary to implement an effective
monitoring process. PRC-004 is focused on Misoperations. PRC-030 should effectively mitigate issues in which protections are not appropriately set to ride through system disturbances when voltage and frequency remain within the "No Trip Zones."
2. The two second period was meant to detect events in which there was a sudden drop in output. If the time period is extended it would include more ramping type events related to the exclusions listed in R1. DT will consider extending possibly up to 10 seconds. Furthermore, storing one-two second facility output data is not a large volume of data, and the GO would only be required to capture and retain data during the event period.
3. MVA was changed to MW in Requirement R1.

Megan Melham - Decatur Energy Center LLC - 5

Answer	Yes
Document Name	

Comment

Capital Power supports NAGF's comments.

The NAGF does not support the proposed language for Requirement R1 and provides the following comments for consideration:

a. The 2 second timeframe to identify unexpected changes in power output may not be possible for existing inverter-based resource (IBR) facilities.

b. The NAGF requests that the 20MVA threshold be revised to reference MW instead of MVA. As currently drafted, there does not appear to be any value gained from having to calculate the MVA before doing any analysis.

c. The NAGF notes that PRC-004: Protection System Misoperation Identification and Correction does not require a documented process to identify misoperations, rather it requires applicable registered entities to identify misoperations and take actions accordingly. Therefore, the NAGF recommends that the proposed PRC-030 Requirement R1 be deleted or modified to align with PRC-004. *d. The NAGF notes that Requirement R1 “shall have a documented process” is purely an administrative documentation effort that provides no benefit to reliability. Note that Paragraph 81 efforts eliminated such administrative burdens from the NERC Reliability Standards and as such the DT should not be including such administrative activities in the proposed PRC-030.* *e. Recommend moving footnote #1 – unexpected changes in output criteria as items listed under Requirement R1.* *f. The NAGF notes that the process and activities proposed under Requirement R1 and R2 better aligns with Generator Operator (GOP) responsibilities rather than Generator Owner (GO).*	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment please see the response to NAGF’s comment.	
Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
The footnote describing what are not “unexpected changes” does not consider small (<5%) system voltages changes caused by shunt reactor or capacitor switching. This means, an IBR plant operating at constant MW (low wind conditions or vars at standstill) but regulating voltage could generate frequent (daily) “unexpected change” events by simply regulating voltage, as planned, and required. A MW requirement instead of MVA would allow to remove all the unwanted error reporting linked to voltage regulation, especially during continuous operating conditions.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment, in Requirement R1 the measure of MVA has been changed to MW. The footnote has also been moved into the Requirements R1 language.	
Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

Yes. As currently defined in footnote 1, "unexpected changes" appears to include BPS events that an IBR responds to *correctly*. For example, a BPS fault occurs and an IBR dynamically responds to the fault event correctly (within 2 seconds) and the IBR returns back to normal pre-disturbance conditions. As currently written in the standard, this type of response would be deemed an "unexpected change" when in fact it is the expected change/performance for an IBR based on interconnection requirements and facility design. Requiring event analysis, or even just the determination of "expected versus unexpected change" for every single fault event across the entire IBR fleet would result in an exorbitant cost and burden to GOs. Elevate does not believe this is necessarily the perspective or intent of the SDT and therefore wants to stress this technical aspect so that this is clarified for the benefit of all stakeholders.

An example of a change to the "unexpected changes" footnote to address this aspect is detailed below:

"Unexpected changes in power output includes any change of generation that is not attributed to factors such as weather patterns, change of wind, change in irradiance, curtailment, ramping, planned outage, planned testing, the loss of a Transmission Line connecting the IBR generators, or expected/intended dynamic responses to grid events."

As mentioned, Requirement R1 also defines the unexpected changes in power output "occurring within a two-second period." While the "within two-second period" is being set to capture dynamic, fast-moving events (e.g., fault events, transients, etc.) rather than the slower expected changes like weather patterns/changes, curtailment, ramping, etc. (i.e. the excluded events), we have a concern that the "within two-second period" will catch all dynamic responses of IBRs to any event on the system, including correct/intended dynamic responses (rather than just capturing abnormal or unexpected response). Furthermore, the "within two-second period" characterization

may miss controller oscillations, control interactions, and slower active or reactive power responses in the wrong direction than intended. These types of unexpected changes should be identified and analyzed as part of this new standard as well. Examples of industry references and requirements of these types of events include: (a) the IEEE 2800-2022 standard, specifically clause 7.2.2.6 "Restore Output After Voltage Ride-Through", which provides active power recovery time following BPS disturbances in the range of 1.0 second to 10 second; and (b) the NERC Reliability Guideline for BPS-Connected IBR Performance provides information on IBR responses occurring longer than two-seconds such as automatic return to service following a trip. Providing guidance in Requirement R1 for the trigger of the events of concern is a good practice but limiting the requirement language to specify only one trigger (e.g., the "unexpected changes in power output occurring with a two-second period") to capture any type of unexpected changes with an IBR will likely result in many types of events being missed, while also capturing many events that don't need to be analyzed (e.g., correct/intended responses of an IBR). The recommendation would be to include a set of event triggers as sub-requirements under Requirement R1. Example triggers could include: (1) unexpected changes in active or reactive power output within a two-second period* (2) unexpected changes in active or reactive power output longer than a two-second period, including momentary cessations and tripping of the IBR plant or individual IBR units. (3) Active or reactive power oscillations that are poorly damped or persist for longer than *[consider value]* seconds; *Note: This is incumbent on the recommended change to "unexpected change" footnote that excludes the *expected* response to grid events. This structure would give the opportunity for additional triggers to be easily added and implemented/considered to more suitably capture unexpected operations occurring from IBRs on the BPS.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment, the Drafting Team will take this into consideration. The definition of an event has been updated to improve clarity.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren believes the threshold in R1 is too low and suggests changing it to 75 MVA to align with PRC-004. We also suggest inserting the phrase "related to a common cause" in the footnote after the word "generation." We also think R3 should be removed as it is redundant with reporting requirements in MOD-032. The new Category 2 registration also creates redundancy within the standard. In the Facilities sections, we believe Bulk Power System should be changed to Bulk Electric System because this term is used more frequently and is better understood. We also think event detection would be too burdensome with the current requirements in R1. Finally, if an IBR is on the Distribution system, is that part of the BPS? In general, Ameren also agrees with EEI's and NAGF's comments.	
Likes 0	
Dislikes 0	
Response	
The DT's response: 1. Thresholds are still under review. 2. GO would not know if their unit's drop in output was related to common cause. 3. Requirement R3 was removed. 4. The applicability section will be coordinated with the new IBR-GO definition. 5. IBR facilities should be able to monitor the facility output and understand why sudden drops in output occur. 6. IBRs on the Distribution System are not included.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	

Answer	Yes
Document Name	
Comment	

The MRO NSRF provides the following feedback:

- Need to ensure that PRC-030 R1 does not include balance of plant (BOP) Protection System already covered under PRC-004-6. An example would be PV & wind generation 34.5kV collection system Protection Systems. This should be addressed in the §4. Applicability as follows “4.2.1. the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.” MRO NSRF requests that the SDT clearly articulate what equipment is within scope for this standard, with special attention paid to any potential overlaps with PRC-030 and PRC-004-6.
- The threshold should simply be a magnitude e.g. 20MVA. Anything less than 20MVA would not affect the Bulk Electrical System pursuant to the definition and is the accepted threshold within industry. This would also more closely align with GADS Event reporting thresholds. In addition, the MRO NSRF would like to understand the justification of why apparent power is the magnitude being used by the SDT?
- 2 second time period. The MRO NSRF does not agree with the rationale for 2s time period “The two second time period, the fastest Supervisory Control and Data Acquisition (SCADA) scanning rate…”. The MRO NSRF suggests “within one-minute” time period. The time period shall start when the first individual generating unit is lost. This aligns with the time-frame traditionally used and this ensures that the events that need to be analyzed are captured without having multiple events or over analysis.
- The MRO NSRF does not agree with Requirement R1 “documented process to identify unexpected changes”. Generator Owners need to analyze “unexpected changes” that meet a threshold. Having a process is unnecessary, not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit.

Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	
Response	

The DT’s response:
1. The SAR states "that IBR loss events (either through protection or control actions) such as those that have occurred numerous times as documented in the NERC disturbance reports are included in the types of events that must be analyzed and mitigated." The DT believes

that there is no overlap. PRC-004 is focused on Misoperations. However, PRC-030 should effectively mitigate issues in which protections are not appropriately set to ride through system disturbances when voltage and frequency remain within the "No Trip Zones." 2. Thresholds for Requirement R1 still under review by DT. The DT agrees that MW should be monitored instead of MVA and language has been changed to reflect this. 3. The two-second period was meant to detect events in which there was a sudden drop in output. If the time period is extended it would include more ramping type events related to the exclusions listed in Requirement R1. DT will consider extended possibly up to ten seconds. 4. DT considered this comment and combined Requirements R1 and R2 into a single requirement. However, DT believes a documented process is necessary to implement an effective monitoring process.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the concerns expressed in the EEI comments for this question.	
Likes 0	
Dislikes 0	
Response	
Please refer to the response to EEI.	
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 the NAGF position in which it does not support the proposed language for Requirement R1 and provides the following comments for consideration: a. The 2 second timeframe to identify unexpected changes in power output may not be possible for existing inverter-based resource (IBR) facilities. b. The NAGF requests that the 20MVA threshold be revised to reference MW instead of MVA. c. The NAGF notes that PRC-004: Protection System Misoperation Identification and Correction does not require a documented process to identify misoperations, rather it requires applicable registered entities to identify misoperations and take actions accordingly. Therefore, the NAGF recommends that the proposed PRC-030 Requirement R1 be deleted or modified to align with PRC-004. d. The NAGF notes that Requirement R1 “shall have a documented process” is purely an administrative documentation effort that provides no benefit to reliability. Note that Paragraph 81 efforts eliminated such administrative burdens from the NERC Reliability Standards and as such the DT should not be including such administrative activities in the proposed PRC-030. e. Recommend moving footnote #1 – unexpected changes in output criteria as items listed under Requirement R1. f. The NAGF notes that the process and activities proposed under Requirement R1 and R2 better aligns with Generator Operator (GOP) responsibilities rather than Generator Owner (GO).	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see NAGF comment response.	
Scott Thompson - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	

PNM agrees with EEI's comments	
Likes 0	
Dislikes 0	
Response	
Please see the response to EEI.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation recommends additional language in R1 requirement to add “occurring withing two-second period or the minimum possible evaluation period with the existing site equipment, not to exceed XXX, and is greater” to add flexibility to the requirement. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the two second time frame has been extended to four seconds in the revised standard.	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	

Comment	
The language in R1 of the standard related to the definition of unexpected changes is clear. However, the "two-second" period requires additional definition before we can implement appropriate detective controls. We assume that this time period refers to two-second intervals rather than any two-second span, or is this up to each entity to determine? We would appreciate clarification prior to submittal for board approval.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the time frame refers to any span.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
• MH requests that the SDT clearly articulate what equipment is within scope for this standard, with special attention paid to any potential overlaps with PRC-030 and PRC-004-6. • MH suggests modifying the R1 to read "Each applicable Generator Owner shall have a documented process to identify unexpected changes1 in power output occurring within a **60-**second period **as result of system disturbance event(s)** and is the greater of either 20% of the plant's gross nameplate rating, or 20 MVA. • 2 second time period. The MH does not agree with the rationale for 2s time period "The two second time period, the fastest Supervisory Control and Data Acquisition (SCADA) scanning rate…". The MH suggests "within 60-seconds" time period. The time period shall start when the first individual generating unit is lost or reduced as result of system event(s). This aligns with the time-frame traditionally used and this ensure that the events that need to be analyzed are captured without having multiple events or over analysis.	
Likes 0	
Dislikes 0	

Response	
PRC-004-6 is focused on misoperation of protective elements while PRC-030-1 is focused on IBR generation loss. The time frame has been extended to 4 seconds. The Drafting Team feels that 60 seconds is too long of an interval to support grid reliability.	
Michael Goggin - Grid Strategies LLC - 5	
Answer	Yes
Document Name	
Comment	
In addition to listing event causes that need not be identified in footnote 1, it may be easier for R1 to specify the types of events that should be screened for further analysis. For example, R1 could require identification of 20 MW/20% drops in output within two seconds due to "unexpected behavior of generator settings and controls," or similar language. The Standard could also GADS forced outage cause codes to clarify which types of outages are to be identified and which are not to be identified. A major concern is that, without greater clarity on the type of events that are to be identified, manually reviewing all events to exclude the event types discussed in the footnote will create a huge compliance burden. For example, the passage of clouds over small to medium solar plants can cause changes in output of 75% of nameplate capacity per second,[1] so the generator operator needs a way to automatically exclude those events from consideration by having greater clarity on the types of events that are to be screened for. {C}[1] https://www.sciencedirect.com/science/article/abs/pii/S0306261917300144	
Likes 0	
Dislikes 0	
Response	
GOs would not know if it was unexpected behavior of generator settings and controls until the analysis is performed. The exceptions that have been moved from the footnote to the Standard Language allow for GOs to dismiss events due to cloud cover, change in wind speed. etc. Outage/Fault codes would be reviewed during the analysis process. It will be up to GOs to develop a process to identify events that that do not fit into the listed exclusions and require further analysis.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	

Answer	Yes
Document Name	
Comment	

AEPC signed on to ACES comments:

ACES appreciates the effort put forth by the SDT in drafting the newly proposed PRC-030-1 Reliability Standard. Crafting an entirely new standard is no small undertaking and we are grateful for the hard work and dedication of the SDT members. ACES believes that draft 1 is an excellent step towards meeting the requirements of FERC Order 901; however, we contend that the current language would benefit from a few modifications.

From a historical perspective, the Reliability Standards have used MVA to classify generating units and to establish a threshold for applicability. Megawatts (MW) is typically used to quantify the changes in generation output and load (e.g., Most Severe Single Contingency, Reporting ACE, EOP-004, MOD-031, CIP-002 Impact Rating, etc.). It is the opinion of ACES that it would be best for PRC-030-1 to conform
to the established convention and utilize MW in lieu of MVA when identifying these event types.

Additionally, it is the opinion of ACES that the phrase “unexpected changes” is overly broad so as to capture what is arguably an edge case scenario. Per the Technical Rationale, the intent of the SDT was to:

“encompass both unexpected decreases (i.e., loss) and unexpected increases (i.e., additions) that may be caused by IBR mis-operations that could affect system reliability. For instance, a battery energy storage system that mis-measures system frequency may unexpectedly enter a charging mode.”

It is our position that the greater risk to the reliability of the BES is from an unexpected decrease in generation not an unexpected increase. We do acknowledge that unexpected increases in generation may also pose a reliability risk to the BES; however, we contend that this has always been the case for all generation types and the incidence rate is statistically insignificant. Using a modified version of the example provided by the SDT in the portion of the Technical Rationale quoted above, please consider the following hypothetical scenario:

- A pumped storage hydro generating unit with a gross nameplate rating of 480 MVA is operating with an active output of 435 MW and 20 MVAR (435.5 MVA).

- During a control system malfunction event, the control system incorrectly calculated system frequency sending an incorrect frequency response signal causing the unit to exhibit a near instantaneous change in power output (note: this control action is commonly called “droop control”).
  - The resulting change in power output is a full 5% step change resulting in a final output of 456.75 MW and 20 MVAR (457.2 MVA).
- The change in apparent power in under 2 seconds is 21.7 MVA.
  - While this is less than 20% of the unit’s gross nameplate rating, it is greater than the minimum 20 MVA threshold specified in PRC-030-1 R1.

Thus, it is our assertion that the risk to the BES from an unexpected increase of 20 MVA is immateria to the generating resource type that caused said increase. In short, we believe that this standard should remain focused only on sudden, unexpected losses caused by IBRs at this time. We believe this approach would more closely align with PRC-004-6.

Lastly, it is ACES’ opinion that the parameters identifying these types of events should be modified to more closely align with the language used in the most recent revision of EOP-004-5. Therefore, we recommend that R2 be struck in its entirety and R1 be modified to use the following language:

“Each Generator Owner that identifies an unexpected loss of aggregated Electrical Energy output at an applicable facility (per Section 4.2) shall, within 120 calendar days, determine if the unexpected loss meets the criteria identified in Part 1.1 and Part 1.2.

1.1 Occurs within a 30-second period and

1.2 Greater than either (whichever is larger):

1.2.1 20% of the IBR’s Normal Rating or

1.2.2 20 megawatts (MW)”

Likes 0	
Dislikes 0	
Response	
Please see the response to ACES.	
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), North American Generator Forum (NAGF), and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 1	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI, NAGF, and MRO.	
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	

The Standards Drafting Team (SDT) needs to ensure that the proposed new Reliability Standard PRC-030-1 does not overlap with the purpose and requirements of PRC-004-6 - Protection System Misoperation Identification and Correction, in which the “unexpected changes in power output” of an IBR are not attributable to a protection system operation or misoperation. This could be accomplished by revising Footnote 1 to state, “Unexpected changes in power output includes any change of generation that is not attributed to factors such as weather patterns, change of wind, change in irradiance, curtailment, ramping, planned outage, planned testing, *protection system operation*, or the loss of a Transmission Line connecting the IBR generators”. In addition, Requirement R1 limits the identification of unexpected power changes to those “occurring within a two-second period” and does not consider slower, unanticipated IBR control system interactions that may cause power oscillations. Two seconds is not long enough for average SCADA systems to quantify the unexpected power changes. SMUD recommends that the time period be increased to “a 60-second period” to allow for greater detection of unanticipated IBR control system interactions that affect the Bulk Electric System.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the DT response: 1. PRC-004 is focused on Misoperations. PRC-030 should effectively mitigate issues in which protections are not appropriately set to ride through system disturbances when voltage and frequency remain within the "No Trip Zones." 2. PRC-030 is focused on events in which there is a sudden drop in active power at an IBR facility. If the time period is extended it would include more ramping type events related to the exclusions listed in Requirement R1. DT will consider extended possibly up to ten seconds.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	

Constellation recommends additional language in R1 requirement to add "occurring withing two-second period or the minimum possible evaluation period with the existing site equipment, not to exceed XXX, and is greater" to add flexibility to the requirement. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
The two second time frame has been extended to four seconds in the revised standard.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF does not support the proposed language for Requirement R1 and provides the following comments for consideration: *a. The 2 second timeframe to identify unexpected changes in power output may not be possible for existing inverter-based resource (IBR) facilities.* *b. The NAGF requests that the 20MVA threshold be revised to reference MW instead of MVA. As currently drafted, there does not appear to be any value gained from having to calculate the MVA before doing any analysis.* *c. The NAGF notes that PRC-004: Protection System Misoperation Identification and Correction does not require a documented process to identify misoperations, rather it requires applicable registered entities to identify misoperations and take actions accordingly. Therefore, the NAGF recommends that the proposed PRC-030 Requirement R1 be deleted or modified to align with PRC-004.* *d. The NAGF notes that Requirement R1 "shall have a documented process" is purely an administrative documentation effort that provides no benefit to reliability. Note that Paragraph 81 efforts eliminated such administrative burdens from the NERC Reliability Standards and as such the DT should not be including such administrative activities in the proposed PRC-030.*	

e. Recommend moving footnote #1 – unexpected changes in output criteria as items listed under Requirement R1.

f. The NAGF notes that the process and activities proposed under Requirement R1 and R2 better aligns with Generator Operator (GOP) responsibilities rather than Generator Owner (GO).

Likes 0	
Dislikes 0	

Response

Thank you for the comment,
a) The two second time frame has been extended to four seconds in the revised standard.

b) MVA has been replaced by MW in the revised standard.

c) The requirement to have a documented process has been combined with the execution. The Standard Drafting Team feels that since a process is needed to detect events it should be documented.

d) see part c above

e) Footnote one has been merged into Requirement R1.

f) The Drafting Team feels that the Generator Owner is ultimately responsible for the performance of the unit.

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	Yes
Document Name	

Comment

WEC Energy Group does not agree with the 20% or 20 MVA threshold. The technical rationale states that “was chosen to be large enough to screen out normal operational events but not so large that it does not detect events that should be analyzed”. We do not agree that it is large enough to screen out normal events. The SAR discusses “misoperations” due to grid disturbances. The thresholds in R1 would capture more events than misoperations due to grid disturbances.

WEC Energy Group proposes that the threshold should be set to at least 75% of the site nameplate for BES IBRs and 20 MVA for Non-BES IBRs to only capture site misoperations/faults. The loss of generation in past disturbances was largely contributed by sensitive IBR trip protection settings and impacted the entire site. The disturbance reports clearly support that R1 should state and mandate evaluation for site misoperations/faults based on thresholds or system disturbance identified by TP, PC, RC, or TO.

In addition, as it’s currently proposed, the requirement of R1 will be difficult to identify. Logic that’s necessary to filter out “unexpected changes” attributed to weather patterns, change of wind and/or change in irradiance factors will be difficult to develop and costly.

The “unexpected changes” attributed to weather patterns, change of wind and/or change in irradiance factors occur on a daily basis in some geographical regions, often multiple times per day and can easily drop the site output by 20MVA.

Likes 0	
Dislikes 0	

Response

Thank you for the comment the Drafting Team will discuss this idea when drafting the new standard. The Drafting Team has made conforming changes to remove “unexpected changes” out of the requirement.

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 feels that it may be appropriate for this requirement to apply to all generators larger than 20 MVA, not just IBRs. Unexpected power swings on all generators need to be explored and mitigated as the risk to each interconnection is similar. SRP's suggestion is to remove BPS IBR facility verbiage in the facilities portion of the applicability section or add language to include all units. SRP also recommends the

standard title be changed to Unexpected Power Output Event Mitigation. Lastly, SRP would like Out of Management Control (OMC) to the factors of power output changes in Note 1.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, Applicability has been revised to align with other IBR standards in draft. Thank you for the title suggestion. Footnote one has been merged into Requirement R1.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
WECC suggests that the SDT should emphasize language to ensure that MVAR support, if lost, is captured as an event as “power output” may be interpreted as simply MWs.WECC also believes the SDT should use the proposed definition of Inverter-Based Resource and not add terms (e.g., IBR “generator”). Note that Project 2023-01 EOP-004 describes power output loss differently and limits it to MW—"The Responsible Entity is not required to report losses due to weather patterns, lack of wind, change in irradiance, fuel unavailability, curtailment, ramping, planned outage, planned testing, failure of SCADA or Telemetering data, or due to the loss of a radial transmission facility that disconnects the IBR generators. WECC believe the SDTs should collaborate and use the same language to describe conditions and criteria.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the Drafting Team’s response is: 1. MVAR changed to MW in Requirement R1. 2. Proposed definition of IBR to be used in PRC-030 standard upon approval.	

3. Similar language used in both Standards with minor differences. The DT will consider telemetry failure to be included as exception in PRC-030.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the concerns expressed in the EEI comments for this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see EEI response.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see MRO response.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	

Answer	Yes
Document Name	
Comment	
Electric Reliability Council of Texas, Inc. (ERCOT) recommends that the threshold for what constitutes an unexpected change under Requirement R1 be modified to be the ***lesser*** of either 20% of the plant's gross nameplate rating, or 20 ***MW***. This would ensure that units with a rating larger than 100 MW would assess events down to 20 MW. The 20% threshold would set the floor for units with a rating of less than 100 MW, which would be appropriate. Under the currently proposed language for Requirement R1, a 500 MW plant would not be required to analyze a 90 MW unexpected change, which is a change that is larger than the full rating of some entire units. This outcome would not be consistent with the objectives of the standard. ERCOT recommends that MW be used as the unit of measurement instead of MVA because MVA includes both real and reactive power. Most IBRs operate in reactive priority mode, which means that MVAR will adjust as needed during the two-second window to support voltage, which may skew any MVA-based measurements. Most ride-through performance failure issues are related to unnecessary tripping of the IBR plant or units or abnormal reduction in active current during the ride-through, both of which would result in unexpected changes in MW output. If the SDT believes unexpected changes in MVAR output should also be assessed, ERCOT recommends that this be addressed separately in a dedicated Requirement with its own criteria to avoid confusion or misapplication.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the Drafting Team response is, the thresholds for Requirement R1 are still under review by the DT. The language in Requirement R1 has changed from MVA to MW.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	

Comment
EEI does not support the proposed language in Requirement R1 due to the following concerns: 1. The use of the term "unexpected changes" adds ambiguity and subjectivity to the requirement and should be removed. 2. The use of footnotes places clarifying information outside of the requirement and should be brought directly into Requirement R1. 3. We suggest replacing "power" with Real Power in order to align with the NERC defined term. 4. EEI asks that the SDT provide some justification for the proposed event trigger (i.e., greater of either 20% of the plant's gross nameplate rating, or 20 MVA). 5. We suggest combining Requirements R1 with R2, similar to other NERC Reliability Standards, in order to negate the need to have a requirement that requires an entity to document a process (R1) and another to implement that process (R2). 6. EEI notes that the SAR states that "[m]ultiple NERC disturbance reports have identified the undesired performance of bulk power system (BPS) connected inverter-based resources (IBRs) during grid faults" yet the proposed Requirement R1 would have IBR GOs capture data on any "unexpected change" on IBR power output. While a laundry list of exclusions is provided, IBR GOs will still have to capture and analyze any event that meets the criteria of R1 and determine why the drop in power output occurred and then save all of the event data except those events that meet the identified exclusions. If left unchanged this will result in a substantial new burden on IBR owners to collect and analyze significant amounts of data that in many cases will not be relatable to any system faults. Necessitating more staff and unrecoverable costs to support this effort, while not achieving the desired improvement in BPS Reliability. While EEI offers the following as clearer language for what has been proposed for Requirement R1, we note that a Requirement such as proposed or aligned with our proposed changes will be very costly and burdensome to IBR GOs. Moreover, the only way to minimize the burden of capturing this data would be to tie these events to system disturbances, which is the root cause of IBR aberrant performance but would require GOs to have ready access to system disturbance information, which may be impractical (See proposed changes below): **R1.** Each Generator Owner shall **implement one or more** documented process**(es)** to **capture and retain IBR system telemetry and IBR alarms data necessary for analyzing IBR performance during IBR or Unit IBR events where there is a decrease in Real** Power output **that is equal to or greater than 20% of the power output of the IBR or IBR Unit, but not less than 20MW,** occurring over a two-second period**. IBR and Unit IBR telemetry and alarm data captured during a specified IBR or Unit IBR event, determined by the responsible IBR GO, to have been the result of one of the following conditions negates the need for the IBR GO to retain the captured data:** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1 Losses in IBR or Unit IBR associated with weather, such as changes in wind, solar irradiance, etc.; or

1.2 Load curtailments, resource ramping, planned outages, planned resource testing; or

1.3 Loss of a transmission line connecting the IBR or Unit IBR.

To address the issue of system disturbance identification within IBR control systems, identified above, the SDT should coordinate with the Project 2021-04 (PRC-028-1) SDT to determine whether Disturbance Monitoring Equipment that will be required under that project could provide triggers into IBR control systems so that IBR Telemetry and IBR system alarms could be efficiently linked with disturbance event seen at IBR facilities. Such linkage, if feasible, would minimize IBR GO data collection, as well as provide useful information that would assist IBR GOs in understanding the impact of disturbances on their equipment while improving their ability to develop Requirement R5 CAPs that efficiently resolve performance issues.

Likes 0	
Dislikes 0	

Response

Thank you for the comment, the Drafting Team has removed unexpected changes from Requirement R1. The DT has also changed the footnotes by pulling it up into the standard and replaced power with Real Power. The team will continue to provide justification for the trigger in the Technical Rationale. DT combined Requirement R1 and Requirement R2 together, but the team disagrees with the assertion that there are too many events to analyze. If there are a significant number of events there is a significant risk to the system. DT will continue to coordinate with both PRC-028 and PRC-029 teams going forward.

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	Yes
Document Name	

Comment

Having a documented process for a performance standard is not required and is purely administrative. PRC-030 should follow PRC-004 which does not require a documented process.

The window of "occurring within a two-second period" should be modified to calculate an average of multiple power readings over a longer period.

The threshold should be described in MW instead of MVA.

The term “unexpected changes” needs more clarification and the criteria should be listed as part of the requirement instead of a footnote.

Likes 0	
Dislikes 0	

Response

Thank you for the comment, the requirement to have a documented process has been combined with the execution. The two second time frame has been extended to four seconds in the revised standard. MVA has been replaced by MW in the revised standard. The definition of an event has been updated to improve clarity.

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	Yes
Document Name	

Comment

OPG supports NPCC Regional Standards Committee’s comments:

"The footnote describing what are not "unexpected changes" does not consider small (<5%) system voltages changes caused by shunt reactor or capacitor switching. This means, an IBR plant operating at constant MW (low wind conditions or vars at standstill) but regulating voltage could generate frequent (daily) "unexpected change" events by simply regulating voltage, as planned, and required. A MW requirement instead of MVA would allow to remove all the unwanted error reporting linked to voltage regulation, especially during continuous operating conditions."	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the DT changed requirement from MVA to MW in Requirement R1. The DT has also moved the footnote into the requirement language to further clarify what constitutes a change in output that should be analyzed.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
Invenergy believes additional language is needed to ensure no overlap of requirements between PRC-004-6 and PRC-030-1. Additionally, to reduce administrative burdens and better align with the language of other like standards, the documented process language should be removed and R2 should be deleted. As currently drafted, R1 requires all data be resolute down to a 2-second or faster interval in order to accurately identify events and filter out events like those detailed in footnote 1. Not all sources of data are capable of being reported at these intervals and the proposed interval could result in inaccurate analysis, over-reporting, and data storage issues.	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment, PRC-004-6 is focused on misoperation of protective elements while PRC-030-1 is focused on IBR generation loss. The two second time frame has been extended to four seconds in the revised standard.

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC

Answer	Yes
Document Name	

Comment

Yes, TEPC agrees with EEI's comments regarding 'to identify unexpected changes' should be removed.

Likes 0	
Dislikes 0	

Response

Thank you for the comment, please see EEI response.

Robert Follini - Avista - Avista Corporation - 3

Answer	Yes
Document Name	

Comment

Avista fully supports PRC-030 and the need to establish performance requirements for IBRs. The first ballot of the standard is a strong step in the right direction to ensure BPS reliability. We agree with EEI’s comments and support the changes suggested in those comments.

Likes 0	
Dislikes 0	

Response

Thank you for the comment, please see the EEI response.

Mike Magruder - Avista - Avista Corporation - 1

Answer	Yes
Document Name	
Comment	
We agree with EEI's comments and support the changes suggested in those comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see the EEI 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	

ACES appreciates the effort put forth by the SDT in drafting the newly proposed PRC-030-1 Reliability Standard. Crafting an entirely new standard is no small undertaking and we are grateful for the hard work and dedication of the SDT members. ACES believes that draft 1 is an excellent step towards meeting the requirements of FERC Order 901; however, we contend that the current language would benefit from a few modifications.

From a historical perspective, the Reliability Standards have used MVA to classify generating units and to establish a threshold for applicability. Megawatts (MW) is typically used to quantify the changes in generation output and load (e.g., Most Severe Single Contingency, Reporting ACE, EOP-004, MOD-031, CIP-002 Impact Rating, etc.). It is the opinion of ACES that it would be best for PRC-030-1 to conform to the established convention and utilize MW in lieu of MVA when identifying these event types.

Additionally, it is the opinion of ACES that the phrase "unexpected changes" is overly broad so as to capture what is arguably an edge case scenario. Per the Technical Rationale, the intent of the SDT was to:

"encompass both unexpected decreases (i.e., loss) and unexpected increases (i.e., additions) that may be caused by IBR mis-operations that could affect system reliability. For instance, a battery energy storage system that mis-measures system frequency may unexpectedly enter a charging mode."

It is our position that the greater risk to the reliability of the BES is from an unexpected decrease in generation not an unexpected increase. We do acknowledge that unexpected increases in generation may also pose a reliability risk to the BES; however, we contend that this has always been the case for all generation types and the incidence rate is statistically insignificant. Using a modified version of the example provided by the SDT in the portion of the Technical Rationale quoted above, please consider the following hypothetical scenario:

- A pumped storage hydro generating unit with a gross nameplate rating of 480 MVA is operating with an active output of 435 MW and 20 MVAR (435.5 MVA).
- During a control system malfunction event, the control system incorrectly calculated system frequency sending an incorrect frequency response signal causing the unit to exhibit a near instantaneous change in power output (note: this control action is commonly called "droop control").
    - The response to an erroneous frequency reading results in a near instantaneous change in power output to 456.75 MW and 20 MVAR (457.2 MVA).
    - The resulting change in apparent power in under 2 seconds is 21.7 MVA.
        - While this is less than 20% of the unit's gross nameplate rating, it is greater than the minimum 20 MVA threshold specified in PRC-030-1 R1.

In summary, as is illustrated in the hypothetical example above, it is our assertion that the risk to the BES from an unexpected increase of 20 MVA is immaterial to the generating resource type that caused said increase. In short, we believe that this standard should remain focused only on sudden, unexpected losses caused by IBRs at this time. We believe this approach would more closely align with PRC-004-6.

Lastly, it is ACES' opinion that the parameters identifying these types of events should be modified to more closely align with the language used in the most recent revision of EOP-004-5. Therefore, we recommend that R2 be struck in its entirety and R1 be modified to use the following language:

"Each Generator Owner that identifies an unexpected loss of aggregated Electrical Energy output at an applicable facility (per Section 4.2) shall, within 120 calendar days, determine if the unexpected loss meets the criteria identified in Part 1.1 and Part 1.2. 1.1 Occurs within a 30-second period and 1.2 Greater than either (whichever is larger): 1.2.1 20% of the IBR's Normal Rating or 1.2.2 20 megawatts (MW)"	
Likes 0	
Dislikes 0	
Response	
The DT thanks you for the comment, the team's response is as follows: 1. The DT agreed and changed Requirement R1 to reflect the change of MW over MVA in the PRC-030-1 standard 2. The DT agreed and has removed the wording unexpected changes. 3. The DT has combined Requirements R1 and R2 together in the new Requirement R1. 4. The DT also has increased to dour seconds and increased number of days determination too in the PRC-030-1 standard.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for the support and comment.
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support and comment.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support and comment.	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	
Document Name	
Comment	

The footnote describing what are not “unexpected changes” does not consider small (<5%) system voltages changes caused by shunt reactor or capacitor switching. This means, an IBR plant operating at constant MW (low wind conditions or vars at standstill) but regulating voltage could generate frequent (daily) “unexpected change” events by simply regulating voltage, as planned, and required. A MW requirement instead of MVA would allow to remove all the unwanted error reporting linked to voltage regulation, especially during continuous operating conditions.

Likes 0	
Dislikes 0	

Response
Thank you for the comment, the DT agreed and has removed the reactive portion of the power change trigger. The DT has changed to a real power trigger (MW).

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	

Comment
Since PRC-030-1 applies to all BES and non-BES connected resources, Texas RE recommends revising section A 4.2.2 Facilities to the following: 4.2. Facilities: 4.2.1. Bulk Power Electric System (BPS BES) Inverter-Based Resources (IBR) 4.2.2. Non-Bulk Electric System (Non-BES) Inverter-Based Resources (IBR) This change would make PRC-030-1 consistent with PRC-028-1 and PRC-024-4 which reference BES and non-BES Inverter-Based Resources.

Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the Drafting team will take this into consideration in the next draft for posting.	
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	
The footnote describing what are not “unexpected changes” does not consider small (<5%) system voltages changes caused by shunt reactor or capacitor switching. This means, an IBR plant operating at constant MW (low wind conditions or vars at standstill) but regulating voltage could generate frequent (daily) “unexpected change” events by simply regulating voltage, as planned, and required. A MW requirement instead of MVA would allow to remove all the unwanted error reporting linked to voltage regulation, especially during continuous operating conditions.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the DT has changed MVA to MW in Requirement R1.	

2. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Allowing the PC or RC to lengthen the two-second period in Requirement R1 may be consistent with the objectives of the standard. There may be instances, such as weak grid or other stability needs, in which slower responses slightly beyond 2 seconds would be required. There may also be other varieties of exemptions. This may also provide a mechanism to account for documented performance characteristics that would not require analysis. This could be addressed by adding the following sentence to footnote one: "Unexpected changes would not include performance that is expected as part of documented RC-, PC-, TP-, or TOP-approved tuning or exemptions."	
Likes 0	
Dislikes 0	
Response	
The two second period was meant to detect events in which there was a sudden drop in output. If the time period is extended it would include more ramping type events related to the exclusions listed in Requirement R1. DT extended the time to four seconds to align with technical monitoring rates (i.e., SCADA scan rates).	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No

Document Name	
Comment	
Please see response in Question 3.	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 5, Weaver Karen
Dislikes 0	
Response	
Thank you for the comment.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
The data capturing requirements are minimal in technical terms and wouldn't require the installation of additional monitoring equipment at a standard IBR installation; most of the compliance effort would be procedural and would be performed regardless by the PUD as part of its regular system disturbance analysis tasks.	
Likes 1	Snohomish County PUD No. 1, 3, Chaney Holly
Dislikes 0	
Response	
Thank you for the 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	No
Document Name	

Comment	
PG&E does not have any alternatives for more cost-effective options.	
Likes 0	
Dislikes 0	
Response	
Thank you for the feedback.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see EEI's response.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State Generation and Transmission supports MRO NSRFs comment.	

Likes 0	
Dislikes 0	
Response	
Please see MRO response.	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
At this time, with unclear direction of intent of responsibility, FirstEnergy cannot determine the cost effectiveness of these proposals.	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment.	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
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	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
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	
It is the opinion of ACES that, as written, PRC-030-1 is not a cost-effective approach. Requiring the GO to identify any unexpected changes in power output occurring within 2 seconds will place an undue compliance burden on the GO. This is particularly true when said power output is measured in MVA. As most facilities monitor output in MW, including MVA will require the GO to either add additional monitoring capabilities or modify existing monitoring equipment to monitor an additional parameter(s). Additionally, requiring the GO to create and maintain a documented procedure as is done in R1, will increase the compliance risk of the GO with no appreciable reduction in risk to the BES. It is ACES' opinion that PRC-030-1 should be modeled after PRC-004-6 by merely requiring the GO to identify applicable event types and allowing the GO the flexibility to perform this task as it sees fit.	
Likes 0	
Dislikes 0	
Response	
The Drafting Team accepted industry proposals to change the monitoring threshold from MVA to MW. Further, the DT removed the separate requirement for a documented procedure, combining it with the requirement to implement the procedure.	
Colin Chilcoat - Invenergy LLC - 6	

Answer	Yes
Document Name	
Comment	
Regarding alternatives and cost-effectiveness, Invenergy has concerns that there is a significant degree of redundancy, and in some instances even conflicts, between the proposed requirements and project goals in PRC-028-1, PRC-029-1, and PRC-030-1. These projects should be aligned to ensure applicable entities do not face duplicative or conflicting requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Please see MRO 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 feels that there could be many alternative and more cost-effective options, so it may be prudent for the drafting team to present some alternatives addressing the FERC Order recommendations for SRP to weigh in.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
The “unexpected changes” attributed to weather patterns, change of wind and/or change in irradiance factors occur on a daily basis in some geographical regions, often multiple times per day and can easily drop the site output by 20MVA. It will be labor intensive to look at each 20MVA drop event and determine if it’s related to unexpected changes unrelated to weather factors. The more cost-effective option is to limit the evaluation to misoperations/faults and if identified by TP, PC, RC, or TO.	
Likes 0	
Dislikes 0	
Response	
Thank you for the feedback. Proactive self-identification of events by GOs is needed based on the types of performance issues noted in NERC Disturbance reports. While identification by other entities is proposed as a "backstop", the DT does not view this as a sufficient primary means of identification.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	

Answer	Yes
Document Name	
Comment	
Please reference all the NAGF comments provided on this comment form for possible cost-efficiencies.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation supports the NAGF comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	

Comment	
The source and impact of the system transients should be evaluated and remedied in addition to or rather than focusing only on the GO facility reaction to the non-normal system conditions. A reduction of or complete elimination in the source of the disturbances is in order. Any buffering or softening of the transmission system abnormal condition's impact on generating facilities, where very sensitive electronic controls are used, would improve GO facility reaction to the disturbances. Adequate transmission system voltage support equipment in weak support areas could lessen the impact of disturbances on IBR based GO facilities.	
Likes 0	
Dislikes 0	
Response	
Please see MRO 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 North American Generator Forum (NAGF) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 2	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please refer to the responses to NAGF and MRO NSRF.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes

Document Name	
Comment	
PRC-030 overlaps with PRC-029 that the SDTs should consider combining some requirements of PRC-030 into PRC-029	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
AEPC signed on to ACES comments: It is the opinion of ACES that, as written, PRC-030-1 is not a cost-effective approach. Requiring the GO to identify any unexpected changes in power output occurring within 2 seconds will place an undue compliance burden on the GO. This is particularly true when said power output is measured in MVA. As most facilities monitor output in MW, including MVA will require the GO to either add additional monitoring capabilities or modify existing monitoring equipment to monitor an additional parameter(s). Additionally, requiring the GO to create and maintain a documented procedure as is done in R1, will increase the compliance risk of the GO with no appreciable reduction in risk to the BES. It is ACES' opinion that PRC-030-1 should be modeled after PRC-004-6 by merely requiring the GO to identify applicable event types and allowing the GO the flexibility to perform this task as it sees fit.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment.	
Michael Goggin - Grid Strategies LLC - 5	
Answer	Yes
Document Name	
Comment	
1. The Drafting Team should add a requirement to R3 that the TO must file its request within 15 days of the disturbance event. This will ensure that the GO has at least five days to pull data before it is overwritten, given that the data retention period in the current draft of PRC-028 R7 is 20 days. 2. In the draft, R4 and R5 specify that the GO has 45 days to complete its analysis report and then another 45 days to develop a Corrective Action Plan (CAP). This is not enough time in many cases, particularly for complex events or truly unexpected generator behavior, analysis of which is likely to present the greatest reliability value. Analyzing events in which a resource failed to ride-through a disturbance is likely to require consultation and coordination with the equipment manufacturer and project engineer, which requires significant time. Reliability would benefit if the time requirements were extended to a more reasonable period, such as 120 days for analysis and then 60 days for developing a CAP. 3. R1 and R2 could be combined and streamlined to remove the administrative and procedural requirements for having a documented process for identifying events, and instead simply require the GO to demonstrate compliance by showing that it has identified and analyzed the events it was supposed to.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Patricia Ireland - DTE Energy - 4, Group Name DTE Energy	

Answer	Yes
Document Name	
Comment	
The requirement to investigate each two-second 20% (or 20 MVA) drop in power output to determine if the drop meets the definition of an “unexpected change” for all NERC regulated IBRs is burdensome and, especially for very small geneating units, not cost-effective compared to the benefit derived. We suggest incorporating into the standard a deminimus capacity rating excluding smaller generators from the scope of this standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
The requirement to investigate each two-second 20% (or 20 MVA) drop in power output to determine if the drop meets the definition of an “unexpected change” for all NERC regulated IBRs is burdensome and not cost-effective for any benefit derived. We suggest a deminimus capacity rating that excludes smaller contributors from the scope of this standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation supports NAGF comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see NAGF response.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
As proposed, the MRO NSRF does not believe that this is cost-effective. Please see all MRO NSRF comments. Additionally, the source and impact of the system transients should be evaluated and remedied in addition to or rather than focusing only on the Generator Owner (GO) facility reaction to the non-normal system conditions. A reduction of or complete elimination in the source of the disturbances is in order. Any buffering of softening of the transmission system abnormal condition's impact on generating facilities where very sensitive electronic controls are used would improve GO facility reaction to the disturbances. Adequate transmission system voltage support equipment in weak support areas could lessen the impact of disturbances on ibr based GO facilities.	

Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	
Response	
Thank you for the feedback. The purpose of this standard, as stated in the SAR, is to monitor, analyze and mitigate the types of IBR performance risks observed in previous NERC disturbance reports. Other standards cover system-level events (e.g., EOP). While grid disturbances are limited to the extent possible, it may not be practical or cost effective to reduce significantly or eliminate entirely as suggested in 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 the comment please see NAGF response.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
As described in AZPSs response to question 1 above, the Requirement as proposed will be very costly and burdensome to IBR GOs. Moreover, the only way to minimize the burden of capturing this data would be to tie these events to system disturbances, which is	

the root cause of IBR aberrant performance but would require GOs to have ready access to system disturbance information, which may be impractical: To address the issue of system disturbance identification within IBR control systems, identified above, the SDT should coordinate with the Project 2021-04 (PRC-028-1) SDT to determine whether Disturbance Monitoring Equipment that will be required under that project could provide triggers into IBR control systems so that IBR Telemetry and IBR system alarms could be efficiently linked with disturbance event seen at IBR facilities. Such linkage, if feasible, would minimize IBR GO data collection, as well as provide useful information that would assist IBR GOs in understanding the impact of disturbances on their equipment while improving their ability to develop Requirement R5 CAPs that efficiently resolve performance issues.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Please reference all the comments provided on this comment form for possible cost-efficiencies.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Natalie Johnson - Enel Green Power - 5	

Answer	Yes
Document Name	
Comment	
It is difficult for the industry to determine the full cost implications of PRC-030. It is premature to determine at this time the cost implications until it is fully known what is involved in the analysis of IBR loss events following grid disturbances.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Srinivas Kappagantula - Arevon Energy - 5	
Answer	Yes
Document Name	
Comment	
Please refer to the comments provided by North American Generation Forum (NAGF) for possible cost-efficiencies.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	

Comment	
IPCO wants to highlight one of the biggest gaps not being addressed with these proposed changes: Utilities are dependent on contractors and can only hold those contractors to contractual terms. When those contractors are outside of NERC jurisdictional authority, the entities can only do some much, outside of their contracts, to make contractors comply and produce evidence. The standards and requirements must be written in ways that allow for entities to be able to comply until there is some level of authority to bring the contractors into the sphere of the NERC jurisdiction. These changes do not address that concern. IPCO encourages improvements that encompass the parts of the relationship with the vendor or Long-Term Service Agreement administrator that the entity can control other than just through contractual means. Relying on a contractor for time-based responses presents challenges if not addressed in this draft.	
Likes 0	
Dislikes 0	
Response	
The DT considered additional entities under the Applicability section prior to the first draft and again after industry comment. The DT suggests that applicability is clearer by including only GOs and owners of appliable IBR facilities, rather than expanding applicability to GOPs to explicitly encompass potential contractual arrangements.	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
WAPA isn’t a GO, however we support the MRO NSRFs feedback: As proposed, the MRO NSRF does not believe that this cost-effective. Please see all MRO NSRF comments. Additionally, the source and impact of the system transients should be evaluated and remedied in addition to or rather than focusing only on the Generator Owner (GO) facility reaction to the non-normal system conditions. A reduction of or complete elimination in the source of the disturbances is in order. Any buffering of softening of the transmission system abnormal condition's impact on generating facilities where very sensitive	

electronic controls are used would improve GO facility reaction to the disturbances. Adequate transmission system voltage support equipment in weak support areas could lessen the impact of disturbances on ibr based GO facilities.	
Likes 0	
Dislikes 0	
Response	
Please see MRO response.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	
Document Name	
Comment	
No comment. Too new and early to determine cost effectiveness.	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
no comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	
Document Name	
Comment	
TEPC agrees with EEI's comment, unkowing the outcome of this newly developed Standard, we do not have a response at this time.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	

Answer	
Document Name	
Comment	
NIPSCO will not comment on cost effectiveness but please see responses to questions 1 and question 3 for recommendations.	
Likes 0	
Dislikes 0	
Response	
The Drafting Team thanks you for the comment.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	

Duke Energy will not submit any input on the cost effectiveness of this newly developed Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Scott Thompson - PNM Resources - 1,3 - WECC,Texas RE	
Answer	
Document Name	
Comment	
PNM has not researched alteratives therefore, cannot comment on more cost-effective options.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
No comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	

Brian Lindsey - Entergy - 1	
Answer	
Document Name	
Comment	
This is too broad of a question and does not pertain to PRC-030-1.	
Likes 0	
Dislikes 0	
Response	
Thank you for the feedback.	

3. Provide any additional comments for the Drafting Team to consider, if desired.	
Brian Lindsey - Entergy - 1	
Answer	
Document Name	
Comment	
• Inverter-Based Resources (IBR) is capitalized but not yet defined. • R5.2. Does not add any value. • Propose a 5-year phased in implementation plan to give adequate time for the GO to implement effective procedures.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the Drafting Team will make sure these updates are considered and may be incorporated into the new draft of PRC-030-1.	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	
Document Name	
Comment	

MRO is voting Negative on the changes to PRC-030-1 because the proposed language in R5.1 was ambiguous regarding which parts of R4 needed to be addressed in the CAP (we understand that the R5.1 CAP is intended to address both R4.1 and R4.2). This ambiguity could cause problems with enforcing R5.	
Likes 0	
Dislikes 0	
Response	
Thank you of the comment and this will be passed along to the Drafting Team.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	
Document Name	
Comment	
Requirement R4: We would prefer to see 120 days which would match PRC-004 but maybe a fair compromise is 90 days. It takes time to collect all the information in some cases since it may require consulting with inverter or PPC OEMs. The requirements for notification would need to be better defined in our opinion. Requirement R5: same comment on time as R4.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The Drafting Team has changed analysis requirement to 90 days. DT has also changed CAP development requirement to 60 days.	
Thomas Foltz - AEP - 5	
Answer	

Document Name	
Comment	

While the scope and general intent of PRC-030 appears reasonable, AEP believes its process and flow is flawed and needs to be changed. Firstly, as currently proposed, the standard process seems to include R1, R2 and R4 within 45 days of an Event which would also include cause identification. This is overly optimistic, especially in those cases where OEM support and insight will be needed, and thus it would be unreasonable to achieve this in all cases. Furthermore, R4 and R5 should both align with the PRC-004 requirements and timeframes so that both standards are consistent with one another. It is not logical to mandate “cause identification” within 45 days (or any time frame for that matter) before the root cause is even determined. While it might be reasonable to simply identify the “event” within 45 days (or 120 days to match PRC-004), additional time will still be needed to research and determine the root cause(s). This could conceivably take 45 days or more, especially if support is needed from the OEM. And once the cause is determined, at least 60 additional days (to match PRC-004) would then be needed to develop the CAP and document the Applicability (R4.2) of that CAP to other facilities. Applicability cannot be documented without first determining the root cause and then the CAP.

The standard infers that it is already “understood” that a qualifying event has occurred and been classified accordingly. As a result, there is no clear establishment of when the clock actually starts on the process.

AEP recommends that there should be a maximum time frame identified for a GO to “identify” that an “applicable Event” has occurred. The standard seems to imply that this will be done per R1/R2 within 45 days of the Event occurring or within 45 days of receiving an R3 data request. PRC-004, by contrast, allows 120 days to identify if an operation was proper, or instead, was a misoperation.

The notification obligations in R4.3 should not be handled within PRC-030, and instead, should be done as routine data requests, perhaps using the NERC Section 1600 data request process or similar.

R4.3 includes the phrase “Notification to each applicable Balancing Authority, Reliability Coordinator, *or* Transmission Operator of the analysis results.” Did the SDT perhaps intend that “and” be used instead of the “or” to require that *all* of them be notified? Similarly, R5 and R6 only require the RC to be notified, and we recommend that the Balancing Authority and Transmission Operator be added to those requirements as well.

R3’s data request turnaround time of “within 30 calendar days” should be changed to be twenty calendar days to align with that of R7 in

PRC-028. In addition, R3 appears to be a potential double-jeopardy issue with PRC-028 R7 data requests. This is further confused by using the generic word "data" in R3. AEP requests that specificity be provided to make it clear exactly what this data *is* and is-*not*, and to specifically note it would not include data required in PRC-028. AEP would suggest going even further, ideally, by simply deleting R3 in its entirety, thereby eliminating any possibilities of double jeopardy by simultaneously violating multiple standards. Implementation Plan: AEP has no objections for the implementation period to be six months for purposes of identification, however a separate implementation period needs to be established for those cases where field equipment changes are necessary. This is greater than simply a "configuration issue", as new equipment may be needed to obtain additional data points. AEP recommends that a period of two calendar years be allowed instead to accomplish whatever field changes may be necessary. The requirements proposed in PRC-030 clearly and appropriately make the GO responsible for the performance of the Invertor-Based Resources and IBR units it owns. AEP recommends the SDTs for PRC-028, PRC-029 and PRC-030 review their 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. AEP does not believe that the Operations Planning time horizon is most appropriate for these requirements. Instead, please consider using the "Operations Assessment." VSLs: The row for R3 does not have an additional column or gradient related to the 30-day requirement. AEP recommends adding an additional column for cases where data is provided but done so in excess of the 30-day threshold. As a result, AEP has chosen to vote "Negative Opinion" on the non-binding poll.

Likes 0	
Dislikes 0	

Response
Thank you for the comments, the Drafting Teams response is: 1. Analysis period extended to 90 days and CAP development period extended to 60 days.

2. Analysis to be complete within 90 days of the event identified in R1 or 90 days within notification of an event identified by RC, BA, or TOP. 3. The Drafting Team believes it should be up to the GO to develop a process to identify and analyze events. Requirement R2 makes it clear that they have 90 days from the date of the event to complete analysis, regardless of when the event was identified. They also have 90 days to complete analysis of events identified by the BA, RC, or TOP from the date they were notified of the event. 4. Analysis results now provided upon request by RC, BA, or TOP. CAP now provided to RC, BA, and TOP. 5. Requirement R3 removed because data acquisition covered in PRC-028.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation supports the additional comments provided by both NAGF and EEI.	
Likes 0	
Dislikes 0	
Response	
See response to NAGF and EEI comments	
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 comments.

1. The Applicability section (A.4.2 Facilities) references BPS IBR. 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. Requirements R1 through R6 reference "Each applicable GO". BC Hydro suggests that the use of "applicable" is redundant once the Section 4 Applicability is updated to reference Category 2 GOs.
3. Requirements R3 as drafted will obligate a GO to provide data to its BA, TOP, or RC regardless of an R1 qualified event occurring (e.g. identification of an unexpected change per R1). The Rationale for Requirement R3 section of the Technical Rationale references "allowing BAs, RCs, and TOPs flexibility to determine thresholds". BC Hydro suggests that additional clarity is required on the "abnormal performance issues" and vis-a-vis the "thresholds" and "methods" that BAs, RCs, and TOPs may adapt to suit their specific needs as indicated in the Technical Rationale. BC Hydro requests that the drafting team clarifies whether the intent behind R3 is to expand of scope beyond the R1 unexpected changes criteria, or to only allow the BA, TOP, or RC to obtain data on R1 events potentially missed by the GO.
4. Requirement R5 appears to assume a zero defect R1 process, i.e. any unexpected change is due to inadequate performance (e.g. misoperation), and a CAP will be necessary for each R2 event. BC Hydro requests that the drafting team provides additional clarity on this expectation as there may be other factors, extrinsic to the IBR performance against design or operational circumstances, that could potentially lead to meeting the R1 threshold and which may not warrant a CAP.
5. The timeline in Requirement R5 is expressed in "days". BC Hydro recommends that the wording be revised to clarify whether it is business or calendar days.
6. BC Hydro recommends that the required analysis timelines be brought into alignment with PRC-004 timelines. These timelines are more reflective of the expected workload associated with obtaining and processing the IBR performance data, and there will likely be additional implementation and sustainment benefits by leveraging existing PRC-004 processes.
7. Requirement R6 Part 6.3 does not include a timeline to notify the RC(s) upon meeting a specified trigger (CAP changes or CAP completion.) Also, the Part 6.3 requirement to notify is not reflected in the VSL Table.
8. The Measures (e.g. M1, M4) include the wording: "Evidence may include, but is not limited to:" followed by an "and" enumeration. Is the intent of the drafting team to set a minimum expectation that all the numbered items must be produced as evidence of compliance, e.g. for Requirement R1 the compliance evidence must include at a minimum (1) a documented process, (2) data recordings AND (3) gross nameplate rating?
9. For Measure M1 BC Hydro suggests that "actual data recordings" may not constitute adequate evidence to substantiate the existence of a documented process, and recommends removing it.

10. 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. 11. BC Hydro recommends that the implementation plan for PRC-030-1 be coordinated with the approval of the approval of the IBR and IBR Unit definitions.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments. 1. The intent of the standard is to apply to all BES IBRs, as is now stated in the Applicability section. 2. We have retained the word "applicable" to indicate that applicability should be considered for each requirement. 3. Requirement R3 is now part of Requirement R2, and has been reworded to clarify its intent. 4. Requirement R2 now clarifies that the event analysis should determine whether a corrective action plan is needed. 5. Timelines expressed in "days" are now expressed in "calendar days". 6. The timeline to analyze events has now been extended to 90 calendar days. 7. The timeline for implementing Requirement R6 (now Requirement R4) is contained in the CAP. 8. It is not the intent that Measures including the phrase "may include, but is not limited to" require all of the items in the list. The word "may" makes that clear; if it were "shall", then all items in the list would be required. 9. Drafting Team believes that data recordings do constitute a useful piece of evidence of Requirement R1. 10. Shall is used routinely in the Measures of other standards. 11. The implementation plan was aligned with other IBR draft standards.	
Ben Hammer - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	
WAPA isn't a GO, however we support the MRO NSRFs feedback:	

- §4 Applicability: Inverter-Based Resources (IBR) currently is not a defined term but is capitalized. Additionally, inverter-based resource needs to be defined prior to approval of PRC-030 to ensure consistency across NERC Reliability Standards. Furthermore, the MRO NSRF would like to know which type of Generator Owner this standard is meant to be applicable to, Category 1 GO and/or Category 2 GOP?
- Time frames in R3 & R4 do not align.
    - Within 30 days supply data for the "identified system level event" to a requestor.
    - Within 45 days GO's must analyze "unexpected changes" that meet a threshold.
    - Generator Owner analysis timeframe shall end first then the timeframe for supplying data should begin. This would be normal/typical order of operations.
    - The MRO NSRF requests the SDT justify the timeframes chosen.
- R4.2. The MRO NSRF does not agree with this requirement as inherently assumes that there is/was an issue with how the individual generator units performed. Each I4 generation facility is unique, it should not be assumed that event conditions can be universally applied.
- R3. & R4.3. The MRO NSRF does not agree with this requirement. This is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit. Further, this data & analysis can be requested under other Standards, IRO-010-4 & TOP-003-5, the RC, TOP & BA should request this data if they believe it is necessary for the purposes of reliability.
- R5. et al. The MRO NSRF does not agree with this requirement as inherently assumes that there is/was an issue with how the individual generator units performed. The MRO NSRF does not agree with "A technical justification that addresses why corrective actions will not be applied nor implemented." This is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit. If the analysis demonstrates the equipment operated correctly, as designed and in compliance with applicable requirements then there should be no need for a Corrective Action Plan. Furthermore, there is no need to require the Corrective Action Plan to be provided to the RC as it can be requested under another Standard, IRO-010-4, the RC should request this data if they believe it is necessary for the purposes of reliability.

Likes 0	
Dislikes 0	

Response

Thank you for the comment, please see MRO response.

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	
Comment	

Language in R2 should be added similar to that of EOP-012-1, R7.1, to allow an explanation of why aspects of the process are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner.

However, we recommend revising PRC-004 to add the elements of this standard, rather than creating a new standard with a similar intent and different timelines. PRC-004 allows 120 days for analysis of Events; it's unclear why PRC-030 would not follow the same timeline. We recommend alignment of PRC-004 and PRC-030 timelines, as there could be overlap or revision of PRC-004 to include unexpected changes of 20% or more of IBRs in scope.

Also, most, if not all, NERC standards are applicable to the Bulk Electric System (BES). Why is this one applicable to the Bulk Power System (BPS) in Section A.4.2.1? Note that the Project Title is "Analysis and Mitigation of **BES** Inverter-Based Resource Performance Issues."

Likes 0	
Dislikes 0	
Response	

Thank you for the comment, PRC-030 focuses on IBR control performance instead of protection relay operation. Hence the Drafting Team decided to create a new standard instead of revising existing protection related standards.
In Section 4.2.1, BPS has been replaced by BES.

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	
Document Name	
Comment	

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. 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 the comment, Applicability has been coordinated with PRC-028-1 and PRC-029-1. The proposed change has been implemented; the intent of the standard is to apply to all BES IBRs.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
FirstEnergy request the DT clarify a term for misoperation of an IBR so that the intent of PRC-030 is clear on intent of industry’s responsibility and response.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment, the DT didn’t use the term misoperation. The scope of the PRC-030 standard is focused on all causes of power changes which may include Misoperations.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
Comments: 1. Overall, ATC agrees that the standard is needed and is addressing an industry need. 2. Clarify if BPS IBRs is inclusive of BES IBRs	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the PRC-030-1 standard is following in suite of the other FERC Order no.901 Standards in which the applicability sections are aligned with one another. The current draft does not use BPS in the facilities section, but rather BES.	
Richard Vendetti - NextEra Energy - 5	
Answer	
Document Name	
Comment	
R1: The language isn’t clear enough. Our Wind SME interpreted it this way:	

I am concerned on the 20% apparent power without any other context on facility size or technology. Example: 67 MVA with 21 2-3 MW turbines. 2-3 turbines dropping would create a self-report and investigation. In Wind, this criteria, may drive a high and maybe unnecessary level of self-reporting (or failure to self-report) and investigations. **R3** – the comment Generator Owner shall provide data – define what this request is. If they can ask for unlimited amounts of data this could become labor intensive. **R4: 4.2 –** clarify the language. Is this asking for Extent of Condition or is this saying were any other sites impacted? Needs more information **R4: 4.1** - There is concern that 45 days may not be enough to complete a full root causes analysis. Request 90 days. **R5: 5.1** - Corrective Action Plan – Is cost prohibitive considered a technical justification? Need to better define constraints much like they are defined in the new EOP-012-1 language. Example: "Could not have been implemented at a reasonable cost consistent with good business practices, reliability, or safety. A cost may be deemed "unreasonable" when implementation of protection measure(s) are uneconomical to the extent that they would require prohibitively expensive modifications or significant expenditures on equipment with minimal remaining life"

Likes 0	
Dislikes 0	

Response	
The Drafting Team modified the thresholds for Requirement R1 to be the greater of 20 MW or 10% of nameplate. The DT believes this threshold balances the elimination of smaller events with having the GO pro-actively engaged with reviewing larger events. The data request requirement was removed. The applicability to other IBR facilities was reworded to state "2.1.4. Determination of the susceptibility of its other IBR facilities to similar events" The analysis timeline was extended to 90 days. Finally NERC is focused on the reliability of the electric system.	
Srinivas Kappagantula - Arevon Energy - 5	
Answer	
Document Name	
Comment	

Arevon Energy provides the following comments for additional consideration.

Section 4: Applicability 4.2 Facilities:

The approved SAR – Project Scope section states "The SAR should be applicable to all BES inverter-based resources.". Therefore, the SDT should revisit the SAR accordingly to ensure that the SDT isnt overstepping their intended scope by including the language in Section 4.2.1. "Bulk Power System (BPS) Inverter-Based Resources (IBR)" Use of the capitalized term "Bulk Power System (BPS) Inverter-Based Resources (IBR)" should be reviewed as it is not a defined in the NERC Glossary of Terms. How can an undefined term be included in a standard? This causes ambiguity over which resources the standard would apply to.

iii. The precise scope of IBRs to be addressed under this standard need to be more clearly defined.

Requirement R2:

Arevon Energy recommends deleting the proposed Requirement R1 and revising Requirement R2 as follows:

"R2 - Each applicable Generator Operator shall identify unexpected changes in power output.".

Requirement R3:

1. Several entities, such as, Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operator (TOP) can request the same data from the Generator Owner (GO). There is potential for duplicity/overlap by allowing multiple entities to request the same data. The BA, RC, and TOP should coordinate any data requests and have a single entity serve as the point of contact with the GO.

2. The NAGF believes that the existing TOP-003 provides the BA, RC, and TOP the ability to request data from the GOs and therefore Requirement 3 is not necessary and should be deleted.

3. Requirement R3 is not needed if analysis of a reportable event is being performed under R4 as R4.3 covers the notofication to the entities in R3.

Requirement R4:

1. The analysis of an event cannot occur unless there was a change in IBR output. Therefore, the reference to Requirement R3 is not required.

2. The timeframes for analysis appear to be much shorter than some other Reliabilty Standards, such as PRC-004 allow. A better approach would be to allow the timeframes for analysis as well as developing a CAP under R5 to align with PRC-004. That woudl be 120 days to conduct analysis and anotehr 60 days to deelop a CAP as needed. This would also ensure reporting consistency across the PRC standards.

3. Requirement 4.2 is an overreach and is at best speculative. This could also be a moot point if entities register each project as its own NCR#, for example.

Requirement R5 & R6:

1. The purpose of the Corrective Action Plan (CAP) needs to be better defined to state what it is intended to accomplish. Extending the CAP to other applicable facilities owned by the GO as mentioned previously is an overreach and speculative at best.

2. There appears to be no value in sharing the CAP with the RC and how the RC would use such information. Recommend to delete this administrative activity from R5.

3. Recommend consistency for the proposed CAP timeframe with other NERC Reliability Standards such as PRC-004.

Likes 0	

Dislikes 0	
Response	

Thank you for the comment, the Drafting Team's response is as follows:

1. The applicability section follows in suite of the FERC Order no. 901, in which all three newly drafted PRC standards facility sections will align. The current draft does not reflect the use of BPS in the facilities section.
2. DT believes GO should have documented processes to identify events. Requirement R1 and Requirement R2 were combined into a single requirement to have a process and identify events.
3. Requirement R3 was removed since data submissions are covered in PRC-028.

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	
Document Name	
Comment	

Tri-State Generation and Transmission supports MRO NSRFs comment.

Likes 0	
Dislikes 0	
Response	

Thank you of the comment, please see MRO response.

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	
Document Name	
Comment	

Please see EEI comments on proposed alternative language and applicability issues

Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see the response to EEI's comment.	
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-030 Section 4. Applicability: 4.1 Functional Entities: 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.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the Drafting Team will consider this comment and pass it along. Thank you for the suggestion.	

Natalie Johnson - Enel Green Power - 5	
Answer	
Document Name	2023-02_Unofficial_Comment_Form_04172024 Enel Comments - Final.docx
Comment	

Enel North America Inc. (Enel) has the following comments on Draft 1 of PRC-030-1:

For Requirement R2, since Enel does not agree with Requirement R1 having a documented process, R2 should be removed.

Regarding Requirement R4.3, Enel believes that notifications to applicable Balancing Authorities, Reliability Coordinators, and Transmission Operators, place an undue burden on all parties and does not align with other performance-based standards, e.g. PRC-004-6. The same can be said for Requirement R5, Corrective Action Plan development, and Requirement R6.3, notifications if Corrective Action Plans actions or timetables change. If Reliability Coordinators deem this information necessary to monitor and assess the operation of its Reliability Coordinator Area, they may use their data specification to solicit information per IRO-010-4. The same mechanisms to retrieve data are in place for Balancing Authorities and Transmission Operators.

Additionally, in regard to development of Corrective Action Plans Enel believes that the drafted language does not allow for events where IBR generator units performed as designed. Instead, there should be specific circumstances outlined for when Corrective Action Plans are required in addition to the analysis required in Requirement R4.

Enel suggests that the SDT revisit the language in Requirement R4 to include similar language as found in PRC-004-6 R1 "…identify whether its Protection System component(s) caused a Misoperation." If the Generator Owner has identified that the unexpected change in power output is a 'misoperation' (the affected IBR did not perform as designed) then a Corrective Action Plan would be required under PRC-030 Requirement R5. In doing such, the SDT should amend PRC-030 Requirement R5.2 to "Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken" as written in PRC-004-6.

Enel supports the comments made by the MRO NSRF regarding defining IBR prior to approval and implementation of PRC-030.

Likes 0	
Dislikes 0	

Response	
The Drafting Team believes that a process needs to be documented in order to be implemented. The documentation and implementation requirements were combined. The data request requirement was removed from the standard. DT revised the requirement to provide analysis to the RC, BA, or TOP only upon request. Language in the new Requirement R3 was revised to account for situations that do not require development of a CAP/technical justification. See response to MRO comments.	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	
Document Name	
Comment	
Capital Power supports NAGF's comments. *The NAGF provides the following additional comments for consideration:* *a) 4.2 Facilities:* *i. The NAGF notes that the approved SAR – Project Scope section states "The SAR should be applicable to all BES inverter-based resources.". Therefore, the NAGF requests that the Drafting Team revisit the SAR accordingly to ensure that the Drafting Team is not overstepping their intended scope by including the language in Section 4.2.1. "Bulk Power System (BPS) Inverter-Based Resources (IBR)".* *ii. 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.*	

iii. The precise scope of IBRs to be addressed under this standard need to be more clearly defined.

b) Requirement R2:

i. For the reasons stated in response to question 1, the NAGF recommends deleting the proposed Requirement R1 and revising Requirement R2 as follows:

"R2 - Each applicable Generator Operator shall implement its process to identify unexpected changes in power output.".

c) Requirement R3:

i. The NAGF is concerned with the potential for duplicity/overlap by allowing the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operator (TOP) to request data from the Generator Owner (GO). Request that the BA, RC, and TOP coordinate any data requests and have a single entity serve as the point of contact with the GO.

ii. The NAGF believes that the existing TOP-003/IRO-010 provides the BA, RC, and TOP the ability to request data from the GOs and therefore Requirement 3 is not necessary and should be deleted.

iii. Requirement R3 is not needed if analysis of a reportable event is being performed under R4.

iv. PRC-030 R3 appears to introduce a potential double jeopardy risk with PRC-028 R7. Both requirements require the GO to provide data to other registered entities. We recommend that PRC-030 R3 should be removed and R4 revised to refer to PRC-028 R7:

"PRC-030-1 R4: Each applicable Generator Owner shall analyze its IBRs performance within 45 calendar days of either the event identified pursuant to Requirement R2 or receipt of a request pursuant to PRC-028-1 R7. The analysis shall include all of the following: ".

d) Requirement R4:

i. The NAGF notes that analysis of an event cannot occur unless there was a change in IBR output. Therefore, the reference to Requirement R3 needs to be deleted. If a system level event occurs, that does necessarily mean any specific generator moved during that time period. If a generator does not move during the period in question, there is nothing to analyze. However, as written, the GO must do an analysis. If the generator sees a change in output under R2, the analysis must be done. The inclusion of R3 data requests triggering an analysis is either duplicative or requiring an analysis when nothing occurred.

ii. The NAGF notes that timeframes provided in PRC-004 should be used for the proposed PRC-030 Requirement R4. The proposed 45-day time period is very short when evaluating what might be required to address an unexpected change in generation.

iii. The NAGF notes that Requirement 4.2 is an overreach/speculative and should be removed accordingly. If the DT believes this requirement to address additional resources should stay in the standard, then the due date for the analysis should be extended a minimum of 60 days per facility to be addressed.

e) Requirement R5:

i. The purpose of the Corrective Action Plan (CAP) needs to be better defined to state what it is intended to accomplish.

ii. The NAGF does not understand the value of sharing the CAP with the RC and how the RC would use such information. Recommend to delete this administrative activity from R5. In addition, if the RC wants this data, they can request it in their data specification under IRO-010.

iii. Recommend the timeframe for the proposed CAP be modified to 60 days for consistency with other NERC Reliability Standards such as PRC-004.

f) Requirement R6:

i. Remove any reference to the RC in R6. To the extent that the RC wants this data, they can request it within their data specification under IRO-010.

g) Implementation Plan

i. The implementation plan states that PRC-028 is needed to allow the proposed PRC-030 to become effective. The NAGF does not see any relationship between the requirement to have data collected at 120 readings per second and the need to evaluate output changes that occur over a two second period. The connection between these two standards needs to be explained.

h) Technical Rationale:

i. The DT mentions that the standard uses MVA instead of MW. However, the SDT does not provide any support for why the MVA value is a better measure than simply MWs. Without some support for the use of MVA and how it might provide a higher level of reliability, the NAGF cannot support the use of a more complicated measurement process. *ii. The rationale for R3 does not make sense based on Requirement R2. It appears that the DT believes that only during a system event would the IBR see this unexpected change. If that is the case, then the BA or the TOP should be expected to initiate the evaluation process, not the GO. The GO does not have wide area view/visibility into the overall electric system. If the intent is to have the GO evaluate unexpected changes in output, regardless of a system event, then R3 is not needed. In addition, TOP-003/IRO-010 allows the BA, RC or TOP to request data for their analysis. R3 is not needed to ensure that the GO provides requested data.* *i) Other Concerns:* *i. The NAGF notes that when PRC-030 becomes effective, we are assuming that IBR GOs will also still need to comply with PRC-004. It's not clear how PRC-030 distinguishes itself from PRC-004 in terms of applicability. We think the Applicability section 4.2 needs to be modified to cover the collector system portion of the Facility. This would depend on the new definition of IBR Unit that is being worked on under Project 2020-06. The Balance of Plant portion should still be covered under PRC-004.* *ii. It is unclear how this standard relates to PRC-028 and PRC-029. Some of the high-level questions we have related to these standard and how they interact with each other include:* *i. Would an "event" identified under PRC-030 be a violation of the proposed PRC-029?* *ii. How is the data recorded under PRC-028 expected to impact PRC-029 and PRC-030?* *iii. Would a change in output due to system conditions exceeding the "Continuous Operating Region" or the "Mandatory Operating Region" defined in PRC-029 still require an analysis and CAP under PRC-030? If so, does that mean an IBR is not allowed to cease injection for any reason under PRC-030?*

Likes 0	
Dislikes 0	

Response
a)I - BPS has been replaced by BES in the latest version of 4.2.1. ii) Revised 4.2.1 per suggestion.

b) Revised standard draft per suggested.

C) ii - This standard has a different scope than TOP-003/IRO-010, and different triggers of requesting data and analysis report. It can't be replaced by TOP-030 and/or IRO-010. iii - in the latest draft, Requirement R3 and Requirement R4 has been merged and one requirement.

d) ii - the analysis time window has been extended to 90 days. iii)-The 4.2 language has been revised as "Determination of the susceptibility of its other inverter-based resource facilities to similar events. " From recent IBR related system disturbance event analysis, DT believes IBR made from same inverter original equipment manufacturer ("OEM") can possibly be susceptible to a similar event.

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 edits to PRC-030-1:

Applicability Section Comments: EEI does not agree that the Applicability Section (4.1. Facilities) is clear. We suggest alignment with the recommendations provided by the Project 2020-06 SDT:

4.1. Facilities:

4.1.1. (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.

Requirements R2 through R6 Comments: EEI suggests the following changes to better align with other NERC Reliability Standards:

R2. Each Generator Owner shall implement its process established in Requirement R1 to identify unexpected changes in Real Power output. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

Propose deleting Requirement R3: EEI disagrees that there is a need for Requirement R3 because there are existing requirements contained within TOP-003 (for TOPs & BAs) and IRO-010 (RCs) that allow these registered entities to obtain this data by simply including the data within their data specifications.

Requirement R4 Proposed Changes: Under PRC-004, responsible entities have 120 days to conduct their analysis of equipment misoperations. At a minimum, the same amount of time is required for IBR GOs to assess aberrant performance of IBRs, noting the analysis of IBR performance is more complex requiring the involvement of vendors and OEMs to fully assess the reasons and possible solutions. Additionally, Requirement R4, subpart 4.3 is unnecessary noting that responsible BAs, RCs, and TOPs can obtain the results of entity analysis through TOP-003 and IRO-010 data specifications.

R4. Each applicable Generator Owner shall analyze its IBRs performance within 120 calendar days of either the event identified pursuant to Requirement R2 or receipt of a request pursuant to Requirement R3. The analysis shall include all of the following: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

4.1. The cause(s) of unexpected change(s) in power output;

4.2. The applicability to its other IBR facilities that could be affected by the same cause of unexpected change(s) in power output; and

Requirement R5 Proposed Changes: Under PRC-004, responsible entities are provided 60 days from the completion of their analysis to the development of a CAP. GOs should be provided the same amount of time. **R5.** Generator Owner shall, within 60 days of completing the analysis in Requirement R4, develop one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]* **4.1.** A Corrective Action Plan (CAP) for the identified Inverter Based Resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R4 Part 4.2; or **4.2.** A technical justification that addresses why corrective actions will not be applied nor implemented. **Requirement R6 Proposed Changes:** Requirement R6, subpart 6.3 should be deleted. There are no similar requirements within PRC-004 and RC reporting requirements are not needed within PRC-030-1. **R6.** Each Generator Owner shall, for each of its CAPs developed pursuant to Requirement R5: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]* **6.1.** Implement the CAP; **6.2.** Update the CAP if actions or timetables change; and	
Likes 0	

Dislikes 0	
Response	
The Drafting Team thanks you for the comment and please see response to EEI.	
Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	
Document Name	
Comment	
As Requirement R5 is the twin requirement of PRC-004 Requirement R5, we suggest using bullets instead of sub-requirements so that the text to both requirements is harmonized and is read the same way. 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 2020-04 (PRC-028) and 2020-02(PRC-029). Section 4.2.1 refers to BPS IBRs, however it is our understanding that section 4. 1.1 would refer to GOs "that own equipment as identified in section 4.2.1" and where section 4.2.1 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."	
Likes 0	
Dislikes 0	
Response	
Thank you for the response, the Drafting Team will ask NERC staff for the appropriate notion. The DT will not use the defined term of IBR since it is not officially defined. The DT will discuss section 4.2 in PRC-030-1 for the additional posting.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	

Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

Requirement R4 will require a rapid event detection and analysis process to abnormal events by all registered IBR owners. Related to the rapid timeframes associated with R4, some additional clarification for Requirement R4.2 is needed. Within the 45 days of an identified event, a GO may be challenged to also identify the applicability of the root cause problem to all its other IBR facilities. Does this applicability work include all owned IBRs across every BA/RC/TOP footprint it operates in, just neighboring IBRs close to the where the event occurred, or is it a system risk mitigation across all similar IBR make/models installed on the entire BPS? This is very critical work to be performed to maintain Bulk Power System reliability but requiring that this analysis occur within 45 days of the system event appears to be a significant burden that may not result in the adequate system risk mitigation that is intended. Rather than putting this applicability work in Requirement R4.2 within the first 45 days, we give the recommendation to remove Requirement R4.2 and place this applicability work into Requirement R5, creating a new R5.2 that mirrors Requirement R4.2 while also requiring a CAP to be implemented for each applicable facility identified in the new R5.2.

For Requirement R5, does the CAP allow the GO to express an open-ended timeline for corrective actions, such as working with the OEM to address an identified change? It is highly unlikely that GOs will have solved the underlying performance issue within a 45-day window

(e.g., coordinating with the OEM). Therefore, it is highly likely that most CAPs will involve a defined/known timeline to work with the OEM to resolve the root cause issues. Those timelines are likely hard to predict or unknown within the 45-day timeline due to challenges that GOs may have coordinating with OEMs (particularly for older inverters). Given that Requirement R6.2 allows for the updating of the CAP as timelines change, it appears this unpredictable time for OEMs to solve some root cause issues will be updated and tracked as part of R6.2. Yet we felt this point of long and unpredictable CAP timelines an important point to highlight to ensure the realities of Requirement R5 and R6 for some root cause issues are understood and thought through. For Requirement R5 and R6, we also believe there may need to be specific callouts in the CAP language regarding updates to the IBR models following root cause event analysis, establishing reasonable timelines and deadlines on the post-event model validation effort. This may touch on the 2025 standards updates regarding Order 901 and should be coordinated early to ensure alignment and minimize the potential re-work. While getting fixes implemented in the field to address the root cause problems is essential, equally important is getting updated models (steady-state, dynamic, EMT model, etc.) with the root cause mitigations included, where applicable, so that the TP/PC have the most accurate, up-to-date IBR models that match what is in the field. Reasonability needs to be given in terms of model validation timelines due to the need to coordinate with the OEM in many cases.	
Likes 0	
Dislikes 0	
Response	
The time window has been extended to 90 days in the new Requirement R2 (i.e., merge of R3 and R4). The time window has been extended to 60 days in the new Requirement R3 (i.e., R5 mentioned in the comment). Model validation requirement is not specifically mentioned in the SAR.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	

Currently there are multiple standards projects in draft including development of IBR and IBR unit defined terms. With this amount of focus and new requirements for IBRs, entities should be given additional time to implement new processes and programs for applicable facilities. A 12 month implementation period would greatly support the success of new IBR compliance programs.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the team and NERC will take this comment into consideration when forming the Implementation Plan.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	MRO-NSRF_2023-02-PRC-030_UCF_04-17-2024_FINAL.docx
Comment	
The MRO NSRF provides the following feedback: • §4 Applicability: Inverter-Based Resources (IBR) currently is not a defined term but is capitalized. Additionally, inverter-based resource needs to be defined prior to approval of PRC-030 to ensure consistency across NERC Reliability Standards. Furthermore, the MRO NSRF would like to know which type of Generator Owner this standard is meant to be applicable to, Category 1 GO and/or Category 2 GOP? The MRO NSRF suggests: 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. • Time frames in R3 & R4 do not align. o Within 30 days supply data for the “identified system level event” to a requestor. o Within 45 days GO’s must analyze “unexpected changes” that meet a threshold.	

o Generator Owner analysis timeframe shall end first then the timeframe for supplying data should begin. This would be normal/typical order of operations.

o The MRO NSRF requests the SDT justify the timeframes chosen. Perhaps aligning with the timeframes of PRC-004-6 is a better option?

- R4.2. The MRO NSRF does not agree with this requirement as inherently assumes that there is/was an issue with how the individual generator units performed. Each I4 generation facility is unique, it should not be assumed that event conditions can be universally applied.
- R3. & R4.3. The MRO NSRF does not agree with this requirement. This is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit. Further, this data & analysis can be requested under other Standards, IRO-010-4 & TOP-003-5, the RC, TOP & BA should request this data if they believe it is necessary for the purposes of reliability.
- MRO NSRF suggests removing 4.3 and 6.3 entirely as they are solely administrative in nature.
- R5. et al. The MRO NSRF does not agree with this requirement as inherently assumes that there is/was an issue with how the individual generator units performed. The MRO NSRF does not agree with “A technical justification that addresses why corrective actions will not be applied nor implemented.” This is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit. If the analysis demonstrates the equipment operated correctly, as designed and in compliance with applicable requirements then there should be no need for a Corrective Action Plan. Furthermore, there is no need to require the Corrective Action Plan to be provided to the RC as it can be requested under another Standard, IRO-010-4, the RC should request this data if they believe it is necessary for the purposes of reliability.

Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	

Response

1. Thank you for the comment, the Drafting team will take this into consideration when drafting the new version of PRC-030-1. The three new PRC standards resulting from FERC Order no. 901 facility sections will be aligned and matching.

2. Requirement R3 removed from Standard and extended the Analysis requirement to 90 days.

3. Drafting Team aligned timeframes for CAP development with PRC-004. Analysis timeframe for PRC-030 is now 90 days whereas timeframe for PRC-004 is 120 days. DT believes 120 days is too long for this analysis in PRC-030. PRC-004 has 120 days to account for events in which many breaker operations need to be analyzed.

3. Intent of this requirement is to analyze if performance issues are systemic to other facilities. If no performance issues identified, this requirement is fulfilled.

5. Requirement R3 has been removed. DT changed standard such that analysis results shall be provided to RC, TOP, and BA upon request.

6. See above response for 4.3. DT believes RC should be notified if timetables for a CAP are changed.

7. Standard has been changed to address this comment. If GO does not identify performance issues during analysis, they no longer have to develop a CAP or provide technical justification why no corrective actions will be implemented.

Daniel Gacek - Exelon - 1	
Answer	
Document Name	
Comment	
Exelon supports the suggested additional edits proposed in the EEI comments for this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see EEI response.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	

Comment	
BPA agrees with R3, as it would allow the BA or TOP to request data regarding disturbances from IBR GOs. Addtionally, BPA seeks clarity if the TP was considered for notification in R5 and R6, as well as the RC? BPA believes there could potentially be differences in IBR behavior in planning studies due to changes in IBRs driven by CAPs required in PRC-030.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, this comment and concern will be passed along to the Drafting Team for discussion and consideration.	
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	
PG&E supports the NAGF additional comments for consideration: a) Requirement R4: i. The NAGF notes that timeframes provided per PRC-004 should be considered for the proposed PRC-030 Requirement R4 to ensure reporting consistency across the PRC standards. b) Requirement R5: i. The NAGF does not understand the value of sharing the CAP with the RC and how the RC would use such information. Recommend to delete this administrative activity activity from R5. ii. Recommend consistency for the proposed CAP timeframe with other NERC Reliability Standards such as PRC-004.	

Likes 0	
Dislikes 0	
Response	
Thank you for the comments. Please see the responses to the relevant NAGF comments.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Scott Thompson - PNM Resources - 1,3 - WECC,Texas RE	
Answer	
Document Name	
Comment	
PNM agrees with EEI's comments. In addition, Inverter-Based Resources (IBR) must be in the NERC glossary of terms before PNM can support the implementation plan and standard PRC-030-1	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment and feedback.	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
Constellation supports NAGF comments and further adds: “Nameplate rating” needs to be clarified as there are many ways to define that especially for solar and storage plant. Recommend revising that to “ 20% of the plant’s real power rating at the Point of Interconnection as defined in the interconnection agreement.” • SDT needs to re-assess the need for R3 as there is overlap with R4. If an entity complies R4, there would be no need for R3. • Analysis completion of IBR performance associated with R4 timeframe needs to be adjusted to 120 days to match PRC-004 . 45 days is not reasonable. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Gross name plate rating is used in the BES definition of generating resources as MOD-025 and MOD-026 Requirement R3 and Requirement R4 are merged in the latest draft. The time has been adjusted to 90 days after of either the event identified pursuant to Requirement R1 or receipt of a request from it’s applicable Reliability Coordinator (RC), Transmission Operator (TOP), or Balancing Authority (BA) that identified a Disturbance and a change in the inverter-based resource(s)IBR active power output.	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	
Document Name	

Comment	
R3/R5: · The 45-day time frame in PRC-030-1 R3, to investigate and determine the cause of an unexpected change is reasonable for straightforward events but is not adequate in a situation when an in-depth analysis is required (particularly if the analysis must be performed by a contracted firm). This timeframe should be modified to align with the 120-day investigation timeline in PRC-004-6 R3. · Similarly, development of a corrective action may be straight forward or complex, requiring contracted services difficult to procure in a timely manner. We suggest that the PRC-030-1 R5 timeline requirement of 45-days be amended to align with the PRC-004-6 R5 (60-days). Implementation Plan: We currently do not have alarming capabilities to identify unexpected changes for IBRs in real-time. We request that the implementation plan include an enforcement date that provides adequate time to implement this newly required detective control and its associated training and documentation.	
Likes 0	
Dislikes 0	
Response	
The Drafting Team extended the analysis timeline to 90 days. PRC-004 120 day timeline accounted for large weather events such as hurricanes which could slow down the event analysis. It is not anticipated that such weather should impact analysis of IBR events. The DT extended the timeline for development of a CAP/technical justification to 60 days. Implementation includes a six-month timeline to implement the process identified in Requirement R1.	
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	
In the technical justification document, some discussion of how the 2s time relates to recent high-profile events is warranted. From reading those reports it was not clear how those events related to the choice of 2s.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the two second period was chosen to identify events in which there is a sudden drop in active power. The two second period has been extended to four seconds since not all facilities have two second telemetry scan rates.	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Patricia Ireland - DTE Energy - 4, Group Name DTE Energy	
Answer	
Document Name	

Comment	
R3/R5: The 45-day time frame in PRC-030-1 R3, to investigate and determine the cause of an unexpected change is reasonable for straightforward events but is not adequate in a situation when an in-depth analysis is required (particularly if the analysis must be performed by a contracted firm). This timeframe should be modified to align with the 120-day investigation timeline in PRC-004-6 R3. Similarly, development of a corrective action may be straight forward or complex, requiring contracted services difficult to procure in a timely manner. We suggest that the PRC-030-1 R5 timeline requirement of 45-days be amended to align with the PRC-004-6 R5 (60-days). Implementation Plan: We currently do not have alarming capabilities to identify unexpected changes for IBRs in real-time. We request that the implementation plan include an enforcement date that provides adequate time to implement this newly required detective control and its associated training and documentation.	
Likes 0	
Dislikes 0	
Response	
The Drafting Team extended the analysis timeline to 90 days. PRC-004 120 day timeline accounted for large weather events such as hurricanes which could slow down the event analysis. It is not anticipated that such weather should impact analysis of IBR events. The DT extended the timeline for development of a CAP/technical justification to 60 days. Implementation includes a six-month timeline to implement the process identified in Requirement R1.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	

Document Name	
Comment	

- R4/R5: During a system-level event the IBR output could change by more than 20% of its MVA rating as a result of voltage change, instantaneous voltage positive phase angle change, or frequency change at the high side of the IBR main transformer. SDT may need to clarify that the analysis should investigate if the change of the IBR output meets the PRC-029 ride-through requirements. The Corrective Action Plan (CAP) could be required if the IBR response does not meet ride-through requirements.
- MH suggests that adding 4.4 “to the IBR change meets the ride-through requirements.
- MH suggests that this project should be aligned with Project 2020-02 (PRC-029).

- We recommend modifying Section 4 of PRC-030-1 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.

- 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-030 should be aligned with Project 2021-04 (PRC-028-1) for the legacy IBRs.

- MH suggests 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 2020-02 (PRC-029). MH 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.

- Time frames in R3 & R4 do not align.

1. Within 30 days supply data for the “identified system level event” to a requestor.
2. Within 45 days GO’s must analyze “unexpected changes” that meet a threshold.
3. Generator Owner analysis timeframe shall end first then the timeframe for supplying data should begin. This would be a normal/typical order of operations.
4. The MH requests the SDT justify the timeframes chosen. Perhaps aligning with the timeframes of PRC-004-6 is a better option?

Likes 0	
Dislikes 0	

Response

The Drafting Team changed the MVA threshold to be based on MWs. In addition, the DT added to the analysis requirement that the GO assess ride-through performance.

The DT modified the analysis requirement to account for situations where the IBR change meets ride-through requirements.

The DT updated the applicability section to align with the other IBR draft standards.

The GO should utilize the best available information until such time that the recording equipment specified in PRC-028 is installed.

The 30-day data request from BA, RC, or TOP was removed.

The DT extended the analysis timeline to 90 days, which is shorter than PRC-004-6, and the development of a CAP/technical justification to 60 days which is the same as the timeline for PRC-004-6. PRC-004 120 day timeline accounted for large weather events such as hurricanes which could slow down the event analysis. It is not anticipated that such weather should impact analysis of IBR events.

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	
Document Name	

Comment

AEPC signed on to ACES comments:

- Section 4 of PRC-030-1 draft 1 includes all Bulk-Power System IBRs; however, this is not in line with the Project Scope as defined in the SAR:

"The SAR should be applicable to all BES inverter-based resources."

While we understand the time constraints placed upon the SDT by FERC Order 901, we would prefer to follow NERC's established processes by modifying the SAR in the event of a scope change.

- Furthermore, we are concerned that as written, this Reliability Standard overlaps with the requirements of PRC-004-6. It is our recommendation that this standard be modified so as to specifically exclude any components already included under PRC-004-6 . In short, it is our opinion that PRC-030-1 should only apply to those event types not covered by PRC-004-6.

Thus, ACES recommends the following changes to Section 4:

- 4.1 Functional Entities:
    - 4.1.1 Generator Owner (GO)
- 4.2 Facilities:
    - 4.2.1 Inverter-Based Resource (IBR) meeting the registration criteria for either a Category 1 or Category 2 GO, with the following exclusions:

4.2.1.1 Protection Systems
4.2.1.2 Special Protection Systems (SPS)
4.2.1.3 Remedial Action Schemes (RAS)
4.2.1.4 Underfrequency Load Shedding (UFLS) that is intended to trip one or more BES Elements
4.2.1.5 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

- Additionally, we at ACES have concerns with the timelines specified in Requirements R3 and R4. Requiring the GO to collect data and analyze an event within 30 calendar days and 45 calendar days respectively is much more stringent than identifying and analyzing similar event types under PRC-004-6 Requirements R1, R2, and R3 (i.e., 120 calendar days). We believe these shortened timelines are overly burdensome to the GO and should be aligned with PRC-004-6.

- Moreover, Requirement R3 does not apply any constraints for how long the BA, RC, or TO have to request the data from the GO. Is the GO expected to store and maintain all data for all applicable IBRs for an indefinite period of time? As the BA, RC, and TO already have the ability to request data from the GO under Reliability Standards IRO-010 and TOP-003, we recommend that Requirement R3 and Requirement Part 4.3 be struck from PRC-030-1.
- Lastly, it is the opinion of ACES that Requirement R5 should be modified such that it only applies when an issue is identified after performing the analysis required by R4. We recommend the following language:

"Each Generator Owner that identifies a performance issue under Requirement R4 shall, within 45 days of completing the analysis, develop a Corrective Action Plan (CAP) for correcting the identified issue. The CAP shall include other applicable facilities owned by the Generator Owner as identified in Requirement R4 Part 4.2 that utilize the same equipment that caused the performance issue.

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Thank you for the comment, Facilities in section 4.2 of the latest draft has been updated as "BES Inverter-Based Resources (IBR)". The ideas will be passed along to the Drafting Team for further consideration.

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	
Document Name	
Comment	
Applicability for PRC-030 should align with PRC-028 and PRC-029	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, in this posting all three PRC standards have aligned the facilities section.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	
Comment	
1 In R1 "plant gross nameplate" is unclear and needs to be better defined, if we have multiple registered generators interconnecting to the same POI are they to be considered separately? 2 There appears to be duplication between PRC-030 R3 and PRC-028 R7, both require GOs to provide data requested by BA/RC/TOP within 30 calendar days. This could introduce double jeopardy and is not necessary, we suggest that PRC-030 R3 is removed. TOP-003 provides further ability for BA/RC/TOPs to request this data. 3 Determining applicability to other IBR facilities under R4.2 is not feasible within 45 calendar days for all cases at larger GOs. We suggest this sub-requirement be granted a more flexible or longer duration timeline with 90 days at minimum. Note that similar requirements in PRC-004 are set to 60 days at the shortest.	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment, these concerns will be passed along to the Drafting Team to be considered when drafting.	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	
Document Name	
Comment	
As Requirement R5 is the twin requirement of PRC-004 Requirement R5, we suggest using bullets instead of sub-requirements so that the text to both requirements is harmonized and is read the same way. 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 2020-04 (PRC-028) and 2020-02(PRC-029). Section 4.2.1 refers to BPS IBRs, however it is our understanding that section 4. 1.1 would refer to GOs “that own equipment as identified in section 4.2.1” and where section 4.2.1 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.”	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the Drafting team has changed the sub requirements in the standard to bullets. The team is not using the defined term and using its own terms separate from project 2020-06 so there is no overlap between the two projects currently. This can be modified and changed in the future once project 2020-06 is completed, if needed. Thank you for the suggestion the team will take this into consideration along with aligning the facilities section with the other FERC Order no.901 facilities sections.	
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), North American Generator Forum (NAGF), and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please refer to the responses to EEI, NAGF, and MRO NSRF.	
Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	

In the applicability section, the precise scope of IBRs needs to be clearly defined rather than stating "GOs with BPS IBRs".

For R3, the request to the GO for data (which must be delivered within 30 calendar days of the request) needs to be required to be made (by the requesting party) within a reasonable time frame after the event occurrence. The GO should not be required to retain all recorded event data ad infinitum.

It seems plausible that a "system level event" (R3) may or may not involve every IBR facility. In the cases where no power output change occurred, the subparts of the analysis listed in the subparts of R4 are not applicable. This should be formally recognized in the requirement.

R3 altogether and the part of R4 referencing R3 (…or receipt of a request pursuant to Requirement R3.) are not needed and should be removed. An event which causes an unexpected change in the power output is called upon to be examined (R4) and delivered to the interested parties (R4.3) elsewhere in this draft standard. If a system event occurs where a specific IBR does not have a unexpected

change in power output, there is no analysis to be done, no need to deliver results to other interested parties, and no need to assume those administrative duties to simply indicate that no unexpected change in power output occurred. What is the reliability benefit for administrative actions enumerated in R4? The analysis specified in R4 can be duplicative of analysis required within the current draft of PRC-029. There should not be duplicative requirements (double jeopardy) in multiple standards. Is R4.3 meant to have the GO provide the results to the requesting party? As written, the GO has a choice as to which of the three parties listed may be sent the results. The timeframes provided per PRC-004 should be considered for the proposed PRC-030 Requirement R4 to ensure reporting consistency across the PRC standards. R5, as written, does not make it clear why a CAP is to be developed. What is the purpose of the CAP? R5, as written, implies that a GO may have multiple RCs to report to - need to reword to "... to its RC" rather than "... to each applicable RC". Events involving existing IBR facilities, in-service before the effective date of PRC-030 and the implementation plan date of PRC-028 (1/1/2030) may not have DME with recording capability for performing a detailed analysis. The implementation plan for existing units should be delayed until PRC-028 requires DME at those locations (1/1/2030). Events involving the Protection System equipment that result in a required investigation to determine if the Protection System correctly operated due to PRC-004 should be exempt from requiring a duplicate analysis with reporting for PRC-030.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the Drafting Team has made changes to the standard to account for these comments. These comments have been passed along to the Drafting Team for consideration.	

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 has the following additional comments for the Standards Drafting Team (SDT) to consider. First, the Applicability section in the proposed PRC-030-1 states: "4.2 Facilities: 4.2.1. Bulk Power System (BPS) Inverter-Based Resources (IBR)."

This language is too broad and would include *all* IBRs interconnected to the Bulk Power System at *any* voltage level. To appropriately reduce the scope of PRC-030-1, the SDT should consider the language proposed in NERC Standards Project 2021-04 Modifications to PRC-002 - Phase II, PRC-028-1 draft #2, which states:

"4.1. Functional Entities:

4.1.1. Generator Owner *that owns equipment as identified in section 4.2* [emphasis added]

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."

Lastly, in Requirement R3, the term "system level event" is not defined. SDT should consider defining this term, or consider other similar changes, so that an IBR owner can be requested to analyze its IBR performance for power system oscillations that do not meet the "20% of the plant's gross nameplate rating, or 20 MVA" criteria in Requirement R1, upon a request from its BA, RC or TOP. This would ensure that IBR Generator Owners are accountable to helping resolve power oscillations in which the IBR's performance may be a contributing factor.

Likes 0	
Dislikes 0	

Response	
Thank you for the comment and suggestion this will be considered when drafting the new version for the facilities section. Language changed to defined term Disturbance. GO would not know if there was a Disturbance and RC, BA, or TOP would need to provide this information upon request for analysis.	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
Constellation supports the NAGF comments and further adds: • "Nameplate rating" needs to be clarified as there are many ways to define that especially for solar and storage plant. Recommend revising that to " 20% of the plant's real power rating at the Point of Interconnection as defined in the interconnection agreement." • SDT needs to re-assess the need for R3 as there is overlap with R4. If an entity complies R4, there would be no need for R3. • Analysis completion of IBR performance associated with R4 timeframe needs to be adjusted to 120 days to match PRC-004 . 45 days is not reasonable. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Gross name plate rating is used in the BES definition of generating resources as MOD-025 and MOD-026 Requirement R3 and Requirement R4 is merged together in the latest draft. The time has been adjusted to 90 days after of either the event identified pursuant to Requirement R1 or receipt of a request from its applicable Reliability Coordinator (RC), Transmission Operator (TOP), or Balancing Authority (BA) that identified a Disturbance and a change in the inverter-based resource(s)IBR active power output.	

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:

a) 4.2 Facilities:

i. The NAGF notes that the approved SAR – Project Scope section states “The SAR should be applicable to all BES inverter-based resources.”. Therefore, the NAGF requests that the Drafting Team revisit the SAR accordingly to ensure that the Drafting Team is not overstepping their intended scope by including the language in Section 4.2.1. “Bulk Power System (BPS) Inverter-Based Resources (IBR)”.

ii. 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.

iii. The precise scope of IBRs to be addressed under this standard needs to be more clearly defined.

b) Requirement R2:

i. For the reasons stated in response to question 1, the NAGF recommends deleting the proposed Requirement R1 and revising Requirement R2 as follows:

“R2 - Each applicable Generator Operator shall implement its process to identify unexpected changes in power output.”.

c) Requirement R3:

i. The NAGF is concerned with the potential for duplicity/overlap by allowing the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operator (TOP) to request data from the Generator Owner (GO). Request that the BA, RC, and TOP coordinate any data requests and have a single entity serve as the point of contact with the GO.

ii. The NAGF believes that the existing TOP-003/IRO-010 provides the BA, RC, and TOP the ability to request data from the GOs and therefore Requirement 3 is not necessary and should be deleted.

iii. Requirement R3 is not needed if analysis of a reportable event is being performed under R4.

iv. PRC-030 R3 appears to introduce a potential double jeopardy risk with PRC-028 R7. Both requirements require the GO to provide data to other registered entities. We recommend that PRC-030 R3 should be removed and R4 revised to refer to PRC-028 R7:

"PRC-030-1 R4: Each applicable Generator Owner shall analyze its IBRs performance within 45 calendar days of either the event identified pursuant to Requirement R2 or receipt of a request pursuant to PRC-028-1 R7. The analysis shall include all of the following: ".

d) Requirement R4:

i. The NAGF notes that analysis of an event cannot occur unless there was a change in IBR output. Therefore, the reference to Requirement R3 needs to be deleted. If a system level event occurs, that does necessarily mean any specific generator moved during that time period. If a generator does not move during the period in question, there is nothing to analyze however, as written, the GO must do an analysis. If the generator sees a change in output under R2, the analysis must be done. The inclusion of R3 data requests triggering an analysis is either duplicative or requiring an analysis when nothing occurred.

ii. The NAGF notes that timeframes provided in PRC-004 should be used for the proposed PRC-030 Requirement R4. The proposed 45-day time period is very short when evaluating what might be required to address an unexpected change in generation.

iii. The NAGF notes that Requirement 4.2 will be addressed under Requirement R5 and it is an overreach/speculative. Therefore, Requirement R4.2 should be removed accordingly. If the DT believes this requirement to address additional resources should stay in the standard, then the due date for the analysis should be extended a minimum of 60 days per facility to be addressed.

iv. Requirement R4.3 should require submittal to TOP, not RC and BA. GOs with many sites will have increased administrative burdens from such reporting activities.

e) Requirement R5:

i. The purpose of the Corrective Action Plan (CAP) needs to be better defined to state what it is intended to accomplish.

ii. The NAGF does not understand the value of sharing the CAP with the RC and how the RC would use such information. Recommend to delete this administrative activity from R5. In addition, if the RC wants this data, they can request it in their data specification under IRO-010.

iii. Recommend the timeframe for the proposed CAP be modified to 60 days for consistency with other NERC Reliability Standards such as PRC-004.

f) Requirement R6:

i. Remove any reference to the RC in R6. To the extent that the RC wants this data, they can request it within their data specification under IRO-010.

g) Implementation Plan

i. The implementation plan states that PRC-028 is needed to allow the proposed PRC-030 to become effective. The NAGF does not see any relationship between the requirement to have data collected at 120 readings per second and the need to evaluate output changes that occur over a two second period. The connection between these two standards needs to be explained.

h) Technical Rationale:

i. The DT mentions that the standard uses MVA instead of MW. However, the SDT does not provide any support for why the MVA value is a better measure than simply MWs. Without some support for the use of MVA and how it might provide a higher level of reliability, the NAGF cannot support the use of a more complicated measurement process.

ii. The rationale for R3 does not make sense based on Requirement R2. It appears that the DT believes that only during a system event would the IBR see this unexpected change. If that is the case, then the BA or the TOP should be expected to initiate the evaluation process, not the GO. The GO does not have wide area view/visibility into the overall electric system. If the intent is to have the GO evaluate unexpected changes in output, regardless of a system event, then R3 is not needed. In addition, TOP-003/IRO-010 allows the BA, RC or TOP to request data for their analysis. R3 is not needed to ensure that the GO provides requested data.

i) Other Concerns:

i. The NAGF notes that when PRC-030 becomes effective, we are assuming that IBR GOs will also still need to comply with PRC-004. It's not clear how PRC-030 distinguishes itself from PRC-004 in terms of applicability. We think the Applicability section 4.2 needs to be

modified to cover the collector system portion of the Facility. This would depend on the new definition of IBR Unit that is being worked on under Project 2020-06. The Balance of Plant portion should still be covered under PRC-004. *ii. It is unclear how this standard relates to PRC-028 and PRC-029. Some of the high-level questions we have related to these standard and how they interact with each other include:* *i. Would an "event" identified under PRC-030 be a violation of the proposed PRC-029?* *ii. How is the data recorded under PRC-028 expected to impact PRC-029 and PRC-030?* *iii. Would a change in output due to system conditions exceeding the "Continuous Operating Region" or the "Mandatory Operating Region" defined in PRC-029 still require an analysis and CAP under PRC-030? If so, does that mean an IBR is not allowed to cease injection for any reason under PRC-030?*

Likes 0	
Dislikes 0	

Response
Thank you for the comment, a) Facilities were revised to align with other draft IBR standards. b) Documented process has been integrated into the execution Requirement of R1 c) The RC and TOP triggers were revised in the new Requirement R2 requirement. The data request portion was removed. The analysis requirements were clarified in the Revised Standard. d) The standard was revised to clarify when a RC or TOP can request an analysis. The timeframes were extended to align with PRC-004-6 more closely. Applicability to other IBR facility language was revised for clarity. Providing the analysis to the TOP, BA, or RC was revised to provide only upon request. e) The DT rephrased the CAP requirement to address performance issues and corrective actions. The DT believes the RC should be aware of any CAPs or technical justifications. f) The DT believes the RC should be aware of CAP changes. g) The Standard Drafting Team agrees that there is no link between PRC-028-1 and PRC-030-1. If PRC-028-1 has been implemented at a facility, then that high-speed data could be used in the analysis for PRC-030-1.

h) The DT changed Requirement R1 to use MW instead of MVA. The standard attempts to strike a balance between GO's being pro-active evaluating necessary MW change events while also allowing for RC, BA, or TOP to initiate events that may not be triggered by the MW thresholds.
i) PRC-030 is intended to cover MW change events that are not associated with relay actions. PRC-028 requires a data recording device which could be used for analysis under PRC-030. PRC-029 established the ride through standards which are assessed in PRC-030. PRC-030 involves the process for evaluating and to the extent needed mitigating MW change events which PRC-029 establishes the ride through requirements. A change in output due to system conditions exceeding the "Continuous Operating Region" or "Mandatory Operating Region" defined in PRC-029 may require an analysis but not require a CAP since the change in MW is expected.

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE recommends including a time period for identifying unexpected changes in power output occurring within a two-second period in accordance with Requirement R1. The GO should have a specific process for identifying the unexpected changes in power output event within specific period to capture these occurrences. Without specific time period, many of the unexpected changes in power output may go unidentified. This could also make it difficult to audit the standard requirement if the entity did not identify any unexpected changes in power output that may have occurred. Texas RE recommends the following revision:

R2. Each applicable Generator Owner shall implement its process established in Requirement R1 to identify unexpected changes in power output **within 30 calendar days of the unexpected change in power output occurred.**

Since Requirements R3 and R4 include a timeline for the GO providing data when requested and the GO analyzing its IBRs' performance, Texas RE recommends including that in the VSLs for Requirements R3 and R4.

Likes 0	

Dislikes 0	

Response

Thank you for the comments, the Drafting Team response:

1. The DT believes it should be up to the GO to develop a process to identify and analyze events. R2 makes it clear that they have 90 days from the date of the event to complete analysis, regardless of when the event was identified. They also have 90 days to complete analysis of an event identified by the BA, RC, or TOP from the date they were notified of the event.
2. Requirement R3 has been removed since data submissions are covered in PRC-028.

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1

Answer	
Document Name	

Comment

This standard is problematic in that it is one of several that are all being enacted piece meal to satisfy the FERC Order. It would be better to have them all together. As currently written, how can a BA request the data if the IBR output is via a Purchased Power Agreement (PPA) only. The IBR is not yet a Generator Owner.

R3 enables the BA, RC, or TOP to request the data that the GO is purportedly being able to provide, but there is no “oversite” of the GO’s process.

R3 contradicts R4. R4 gives the GO 45 days to analyze the IBR performance, but R3 requires the results to be provided within 30 days of the request. If the data requested from the GO in R3 (within 30 days of request) is different from the analysis requested in R4 (within 45 days of request), then the types of data required by R3 should be specified (or at least an example provided).

R5/R6. There is no specificity in how long the initial CAP can be set. If the plan is to fix them over the next 20 years, no updates would ever be required. There is no mechanism for the BA, RC, or TOP to hold the GO to hurry things along or follow “good engineering principles”.

Compliance section 1.2 R4 bullet: a reference is made to a “declaration”. Where does it state that any declaration needs to be made. What declaration is being referred to here?

Likes 1	Tallahassee Electric (City of Tallahassee, FL), 5, Weaver Karen
Dislikes 0	
Response	
Thank you for the comment, the Drafting Team will take this into consideration when drafting the new version of PRC-030-1.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	

Duke Energy suggests the implementation of the following Duke Energy, EEI and NAGF review comments. Duke Energy EEI and NAGF comment modifications are bracketed by asterisks.

EEI COMMENTS

EEI offers the following additional edits to PRC-030-1:

Applicability Section Comments: EEI does not agree that the Applicability Section (4.1. Facilities) is clear. We suggest alignment with the recommendations provided by the Project 2020-06 SDT (See boldface changes below):

4.1. Facilities:

4.1.1. (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 kV.

Requirements R2 through R6 Comments: EEI suggests the following changes to better align with other NERC Reliability Standards:

R2. Each Generator Owner shall implement its process established in Requirement R1 to identify unexpected changes in **Real Power** output. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

Propose deleting Requirement R3: EEI disagrees that there is a need for Requirement R3 because there are existing requirements contained within TOP-003 (for TOPs & BAs) and IRO-010 (RCs) that allow these registered entities to obtain this data by simply including the data within their data specifications.

R3. DELETE

Requirement R4 Proposed Changes: Under PRC-004, responsible entities have 120 days to conduct their analysis of equipment misoperations. At a minimum, the same amount of time is required for IBR GOs to assess aberrant performance of IBRs, noting the analysis of IBR performance is more complex requiring the involvement of vendors and OEMs to fully assess the reasons and possible solutions. Additionally, Requirement R4, subpart 4.3 is unnecessary noting that responsible BAs, RCs, and TOPs can obtain the results of entity analysis through TOP-003 and IRO-010 data specifications. (see changes in boldface below)

R4. Each applicable Generator Owner shall analyze its IBRs performance within **120** calendar days of either the event identified pursuant to Requirement R2 or receipt of a request pursuant to Requirement R3. The analysis shall include all of the following: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

4.1. The cause(s) of unexpected change(s) in power output;

4.2. The applicability to its other IBR facilities that could be affected by the same cause of unexpected change(s) in power output; and

4.3. DELETE

Requirement R5 Proposed Changes: Under PRC-004, responsible entities are provided 60 days from the completion of their analysis to the development of a CAP. GOs should be provided the same amount of time.

R5. Generator Owner shall, within **60** days of completing the analysis in Requirement R4, develop one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. A Corrective Action Plan (CAP) for the identified Inverter Based Resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R4 Part 4.2; or

4.2. A technical justification that addresses why corrective actions will not be applied nor implemented.

Requirement R6 Proposed Changes: Requirement R6, subpart 6.3 should be deleted. There are no similar requirements within PRC-004 and RC reporting requirements are not needed within PRC-030-1.

R6. Each Generator Owner shall, for each of its CAPs developed pursuant to Requirement R5: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

6.1. Implement the CAP;

6.2. Update the CAP if actions or timetables change; and

6.3. DELETE

NAGF COMMENTS

The NAGF provides the following additional comments for consideration:

a) 4.2 Facilities:

i. The NAGF notes that the approved SAR – Project Scope section states "The SAR should be applicable to all BES inverter-based resources.". Therefore, the NAGF requests that the Drafting Team revisit the SAR accordingly to ensure that the Drafting Team is not overstepping their intended scope by including the language in Section 4.2.1. "Bulk Power System (BPS) Inverter-Based Resources (IBR)".

ii. Use of the capitalized term "Bulk Power System (BPS) Inverter-Based Resources (IBR)" should be reviewed as it is not defined in the NERC Glossary of Terms.

iii. The precise scope of IBRs to be addressed under this standard needs to be more clearly defined.

b) Requirement R2:

i. The NAGF recommends deleting the proposed Requirement R1 and revising Requirement R2 as follows:

"R2 - Each applicable Generator Operator shall implement its process to identify unexpected changes in power output.".

c) Requirement R3:

i. The NAGF is concerned with the potential for duplicity/overlap by allowing the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operator (TOP) to request data from the Generator Owner (GO). Request that the BA, RC, and TOP coordinate any data requests and have a single entity serve as the point of contact with the GO.

ii. The NAGF believes that the existing TOP-003 provides the BA, RC, and TOP the ability to request data from the GOs and therefore Requirement 3 is not necessary and should be deleted.

iii. Requirement R3 is not needed if analysis of a reportable event is being performed under R4.

d) Requirement R4:

i. The NAGF notes that analysis of an event cannot occur unless there was a change in IBR output. Therefore, the reference to Requirement R3 needs to be deleted.

ii. The NAGF notes that timeframes provided per PRC-004 should be considered for the proposed PRC-030 Requirement R4 to ensure reporting consistency across the PRC standards.

iii. The NAGF notes that Requirement 4.2 is an overreach/speculative and should be removed accordingly. *****R4.2 is already included in R5 and should be removed. During the CAP, the GOP will determine if the problem applies to other sites.*****

iv. *****R4.3 should require submittal to TOP, not RC and BA. GOs with many sites will have increased administrative burdens for reporting activities.*****

e) Requirement R5:

i. The purpose of the Corrective Action Plan (CAP) needs to be better defined to state what it is intended to accomplish.

ii. The NAGF does not understand the value of sharing the CAP with the RC and how the RC would use such information. Recommend to delete this administrative activity from R5.

iii. Recommend consistency for the proposed CAP timeframe with other NERC Reliability Standards such as PRC-004.

Likes 0	
Dislikes 0	

Response

Thank you for the comment, please see response to NAGF's comment and EEI's comment.

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	
Document Name	

Comment

R2. - This is an unnecessary requirement as it is not in alignment with other performance analysis standards. It should be removed.

R3. - This requirement seems to be redundant to PRC-028, requirement R7. It should be removed.

R4. - The requirement needs to define that only misoperations/faults need to be analyzed. R5. - The requirement needs to be revised to state that CAP is not needed if IBR reacted as designed.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the Drafting Team will take these comments into consideration when drafting the new version of PRC-030-1.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
WECC suggests that the SDT should consider the definition of Inverter-Based Resource being developed. As is, the "Facilities" section is not consistent with other Standards being developed. Additionally, Inverter-Based Resource should be used instead of "plant" in R1. Consider the use of IBR or Inverter-Based Resource for consistency throughout Standard (e.g., R3/R4 uses IBR, R4 additionally uses IBR facilities, R5 uses Inverter-Based Resource and R1 uses plant). The Technical Rationale description "system level event" is accurate but may limit a BA/RC/TOP approach to IBRs response review. Project 2023-01 limits loss to MWs (current ≥ 500 MW) which is different from the expected response review criteria as explained in the Technical Rational. Voltage collapse scenarios can be localized and IBR responses would need to be reviewed to understand the reasons (and mitigate future risk of re-occurrence). WECC believes GOs should analyze performance of Inverter-Based Resources if the criteria is met in R1 without needing a system level event to be identified.	

Providing the analysis of the response to the RC, BA, and TOP but only providing the CAP to the RC leaves a gap in reliability for the BA. How does planning (TP or PC) receive the response analysis information or the CAP actions that may impact planning models? Technical Rationale mentions “acceptable” technical justification expectations that could essentially negate mitigation of risk. Since this Standard is around “unexpected” occurrences, interconnection requirements may need to be updated to mitigate risks (see multiple event reports regarding Inverter-Based Resource losses). Allowing a GO to provide that technical justification may cause entities to take no action which does not support reliable operations. Suggest dropping “material modification” as the term was removed from FAC -002 Standard and replaced with “qualified change”. FAC-002 should be considered by the GOs and a “qualified change” that impacts reliability should not go unresolved. As is, there is no language regarding approval of the CAP or any specific maximum time limit for a CAP which implies an operational risk could go unresolved for an indefinite period. WECC appreciates the “operating restrictions” comments in the Technical Rationale but system conditions (or the political environment) may not allow a BA/RC/TOP to implement those restrictions (assuming including disconnecting the Inverter-Based Resource). The applicability sectioin indicates that this standard is limited to BPS Inverter-Based Resources. WECC interpprets this to be excluding non-BPS Inverter Based Resources? As non-BES Inverter-Based Resources proliferate, performance may need reviewed and should be considered.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the Drafting Team response: 1. Thank you for the comment, the DT has made changes to the facilities section to align with other FERC Order no. 901 PRC standards. 2. 500 MW threshold in Project 2023-01 is for aggregate MW loss during system level event. PRC-030 threshold in Requirement R1 is for individual unit. There are no minimal thresholds for an RC, BA, or TO to require analysis for an event they identify. 3. A system level event does not need to be identified for Requirement R1. 4. CAP now provided to RC, BA, and TOP.	

5. DT decided not to place requirements on RC, BA, or TOP to review and approve CAPs at this time. 6. Thank you for the comment, the Drafting Team will review and update the facilities section.	
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	
As Requirement R5 is the twin requirement of PRC-004 Requirement R5, we suggest using bullets instead of sub-requirements so that the text to both requirements is harmonized and is read the same way. 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 2020-04 (PRC-028) and 2020-02(PRC-029). Section 4.2.1 refers to BPS IBRs, however it is our understanding that section 4. 1.1 would refer to GOs “that own equipment as identified in section 4.2.1” and where section 4.2.1 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.”	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the Drafting Team will take these suggestions into consideration when revising the draft of PRC-030-1.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	

Answer	
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment please see MRO response.	
Kinte Whitehead - Exelon - 3	
Answer	
Document Name	
Comment	
Exelon supports the suggested additional edits proposed in the EEI comments for this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see EEI response.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

The language in Requirement R3 should be restructured to clarify that the BA, RC, or TOP may require the GO to initiate and perform analysis related to System-level events, which is the intent of this requirement. Additionally, the requirement to provide “data” when requested should be expanded to also require the provision of “information” when requested. As reflected in recent changes made to IRO-010 and TOP-003, the term “information” encompasses more than just data (e.g. PMU/DFR/DDR/SCADA data) and may include settings, OEM documentation, unit parameters, etc.

The SDT should ensure that the timelines in Requirement R4 are consistent with the timelines used for the Event Analysis program. If 45 calendar days are needed for an R4 analysis, then the SDT should coordinate with the Event Analysis Subcommittee (EAS) to coordinate the Event Analysis program timelines as needed.

Under Requirement R5.1, the CAP should, if possible, use the IBR and IBR Unit definitions that are being developed in Project 2020-06, both to ensure consistency and to clarify that the CAP may at times not be for the entire plant but for individual turbines or inverters. Based on the responses provided during the Project 2020-02 webinar, ERCOT is concerned that this SDT may be assuming the Project 2020-02 SDT is addressing the issue of partial reductions in output (IBR unit trips/abnormal reduction) not being allowed, while the Project 2020-02 SDT may be assuming this SDT is addressing that topic. Regardless of which SDT ultimately addresses the topic, the two SDTs should work together to ensure consistency among their respective standards and to ensure that the standards clearly provide that partial reductions in output (IBR unit trips/abnormal reductions) would constitute a performance failure even if the entire plant does not trip.

Requirement R5.2 inappropriately allows GOs to avoid implementing corrective actions without receiving an assessment of the resulting reliability impact or any sort of oversight or pre-approval. If, consistent with FERC Order 901, planners and coordinators must take System-level actions to address the reliability impacts of exemptions or performance failures (the mitigation of which may take months or even years to implement without a firm requirement on timeliness), leaving corrective actions unimplemented at the IBR or IBR Unit level may create a reliability gap until System-level mitigations are implemented (if System changes can even practically resolve the reliability

impact, which is not certain). Unmitigated ride-through performance failures can, in aggregate, have an impact that triggers UVLS, UFLS, Cascading outages, instability, and uncontrolled separation. Requirement R6 should include language that requires the CAP to be implemented as soon as practicable and no later than a specific deadline (e.g., 90 days) unless otherwise approved by the RC. Otherwise, CAPs could take years to implement or never be implemented at all. While ERCOT agrees that, as described in the Technical Rationale, one way of mitigating this risk is to impose operating restrictions that incentivize timely CAP implementation, it would be better to address this issue in the Requirement instead of in the Technical Rationale. This is especially important since NERC has prioritized planner and operator requirement changes ordered in FERC Order 901 after the initial wave of projects, and these two issues are explicitly linked (operating restrictions may be needed to address reliability risks that arise from exemptions or unmitigated performance failures). Assuming that future projects will address this issue does not adequately or timely address this reliability risk; consequently, this issue should be addressed in this standard, especially given that some Generator Owners continue to dispute RC authority to impose operating restrictions.	
Likes 0	
Dislikes 0	
Response	
1. Requirement R3 has been removed since data submission is covered in PRC-028. Requirement R2 allows for BA, RC, or TOP to require analysis for events that they identify. 2. The Drafting Team will consult with NERC EA team. 3. PRC-030 to use IBR definitions from Project 2020-06. Partial trips are implied to be handled in PRC-030 due to the thresholds defined in Requirement R1, and would be analyzed in Requirement R2. BA, RC, and TOP may also require analysis for events they identify in Requirement R2 and there is no minimum threshold. 4. This would require a requirement on the RC, BA, or TOP to review the analysis and the CAP or technical justification and approve or reject. The DT has decided not to place such a requirement on the RC, BA, or TOP at this time.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	

Answer	
Document Name	
Comment	

EEI offers the following additional edits to PRC-030-1:

Applicability Section Comments: EEI does not agree that the Applicability Section (4.1. Facilities) is clear. We suggest alignment with the recommendations provided by the Project 2020-06 SDT (See proposed changes below):

4.1. Facilities:

4.1.1. (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.

Requirements R2 through R6 Comments: EEI suggests the following changes to better align with other NERC Reliability Standards:

Propose combining Requirement R2 with R1: See EEI's justification within our response to question 1.

Propose deleting Requirement R3: EEI disagrees that there is a need for Requirement R3 because there are existing requirements contained within TOP-003 (for TOPs & BAs) and IRO-010 (RCs) that allow these registered entities to obtain this data by simply including the data within their data specifications.

Requirement R4 Proposed Changes: Under PRC-004, responsible entities have 120 days to conduct their analysis of equipment misoperations. At a minimum, the same amount of time is required for IBR GOs to assess aberrant performance of IBRs, noting the analysis of IBR performance is more complex requiring the involvement of vendors and OEMs to fully assess the reasons and possible solutions. Additionally, Requirement R4, subpart 4.3 is unnecessary noting that responsible BAs, RCs, and TOPs can obtain the results of entity analysis through TOP-003 and IRO-010 data specifications. (See proposed changes below)

R4. Each applicable Generator Owner shall analyze its IBRs performance within **120** calendar days of either the event identified pursuant to Requirement R2 or receipt of a request pursuant to Requirement R3. The analysis shall include all of the following: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

4.1. The cause(s) of unexpected change(s) in power output;

4.2. The applicability to its other IBR facilities that could be affected by the same cause of unexpected change(s) in power output; and

Requirement R5 Proposed Changes: Under PRC-004, responsible entities are provided 60 days from the completion of their analysis to the development of a CAP. GOs should be provided the same amount of time. (see proposed changes below)

R5. Generator Owner shall, within **60** days of completing the analysis in Requirement R4, develop one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1 A Corrective Action Plan (CAP) for the identified Inverter Based Resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R4 Part 4.2; or

5.2 A technical justification that addresses why corrective actions will not be applied nor implemented.

Requirement R6 Proposed Changes: Requirement R6, subpart 6.3 should be deleted. There are no similar requirements within PRC-004 and RC reporting requirements are not needed within PRC-030-1. (see proposed changes below)

R6. Each Generator Owner shall, for each of its CAPs developed pursuant to Requirement R5: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

6.1. Implement the CAP;

6.2. Update the CAP if actions or timetables change; and

Likes 0	
Dislikes 0	

Response

Thank you for the response, the Drafting Team response has modified Section 4.1.1 – the DT agreed and increased time to 60 days for old Requirement R5. These comments will be passed along to the DT for further discussion when drafting PRC-030-1.

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	
Document Name	

Comment

The period to analyze IBR performance within 45 calendar days should be increased to 120 days to match PRC-004 and allow time to determine the root cause especially if OEM support is required.

NIPSCO also recommends that the SDTs for PRC-028, PRC-029, and PRC-030 review their proposed standards to ensure there is a consistent plan to achieve the goal of correcting IBR performance issues.

The period to develop CAP should be within 60 calendar days instead of 45 days to align with PRC-004.

The notification in R4.3 is confusing as written, “to each applicable Balancing Authority, Reliability Coordinator, or Transmission Operator”, is the notification supposed to be to all listed, in which case the “or” should be “and”.

The implementation period of six months would be adequate for the purpose of identification, but if equipment changes or upgrades are needed to comply the period should be increased to 2 years to allow for these changes or upgrades.

Likes 0	
Dislikes 0	

Response

Thank you for the comment,
1. Analysis period extended to 90 days. The Drafting Team believes 120 days is too long for this analysis. PRC-004 has 120 days to account for events in which many breaker operations need to be analyzed.

2. The DT for PRC-030 has reviewed and coordinated with PRC-028 and PRC-029.

3. The CAP development period changed to 60 days.

4. Analysis results now shall be provided to RC, BA, or TOP upon request.

5. DT is unaware of any equipment changes or upgrades needed to fulfill these requirements.

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	
Document Name	

Comment

OPG supports NPCC Regional Standards Committee's comments:

"As Requirement R5 is the twin requirement of PRC-004 Requirement R5, we suggest using bullets instead of sub-requirements so that the text to both requirements is harmonized and is read the same way.

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 2020-04 (PRC-028) and 2020-02(PRC-029). Section 4.2.1 refers to BPS IBRs, however it is our understanding that section 4. 1.1 would refer to GOs “that own equipment as identified in section 4.2.1” and where section 4.2.1 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.”"	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the Drafting Team has changed to the sub bullets. Thank you for the suggestion this will be passed on to the DT to be considered when revising PRC-030-1.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	
Document Name	
Comment	
Invenergy thanks the drafting team for their work and the opportunity to provide comments. The Applicability section would benefit from alignment with the other IBR-focused standards in development. As currently drafted, PRC-028-1, PRC-029-1, and PRC-030-1 all use different language to describe the same applicable Facilities. Regarding the timeline in requirement R4, 45 days is not enough time for sufficient analysis. In almost all cases, evaluation and analysis will need to be supported by IBR OEMs, and it is not guaranteed that resources exist to provide feedback that quickly.	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment, applicability has been coordinated with PRC-028-1 and PRC-029-1. The intent of the standard is to apply to all BES IBRs, as is now stated in the Applicability section. The 45-day requirement has been modified to 90 days. Note that Requirement R4 is now Requirement R2.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	
Document Name	
Comment	
On behalf of the SERC Generator Working Group: Applicability section: Is the intent to capture the new Category 2? Suggest defining more precisely. Also, has BPS been used before it defining facilities? For R4.3, we suggest eliminating R3 altogether along with the reference to R3 in R4 because the residual part of the requirement will achieve delivering the analysis of any unexpected output change to the parties of R3. If no change was detected at the plant, no analysis was required, and no reporting should be necessary. (and the request that may come from R3 would yield nothing more than an acknowledgment of no change detected, which is of no value).	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the Drafting Team has changed the facilities section to match and align with other the FERC Order no.901 PRC standards. BPS is not included in the most up to date version of the standard. Requirement R3 has been removed.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	
Document Name	

Comment	
TEPC agrees with EEI comments to revise Section 4.1 Facilities, combining requirement 1-2, deleting requirement 3 to remove duplication of efforts, and revising requirements 4-5 the number of days for analysis.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, this will be passed along to the Drafting Team for consideration when drafting.	
John Pearson - ISO New England, Inc. - 2	
Answer	
Document Name	
Comment	
The timelines in R3 and R4 don't seem to make sense and appear to contradict. If there's a system level event, does this specify that there are 30 or 45 days to respond? In any case, either 30 or 45 days is a very long period of time to analyze unexpected changes in generator power output . We believe that it could and should be done within 5 to 7 business days. It's likely part of a larger investigation that would take weeks to do AFTER receiving the IBR information. Within 30 days there should be a final report (not 45 days) per R4. Given the information that these installations have access to, providing the information in 5 to 7 business days should be reasonable.	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment, Requirement R3 has been removed. Data submission requirements covered in PRC-028. The GO now has 90 days to perform analysis in Requirement R2.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
Avista agrees with EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to EEI's comment.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	
Document Name	
Comment	
We fully support PRC-030 and the need to establish performance requirements for IBRs. The first ballot of the standard is a strong step in the right direction to ensure BPS reliability. We agree with EEI's comments and support the changes suggested in those comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to EEI's 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	

- Section 4 of PRC-030-1 draft 1 includes all Bulk-Power System IBRs; however, this is not in line with the Project Scope as defined in the SAR:

"The SAR should apply to all BES inverter-based resources."

While we understand the time constraints placed upon the SDT by FERC Order 901, we would prefer to follow NERC's established processes by modifying the SAR in the event of a scope change.

- Furthermore, we are concerned that as written, this Reliability Standard overlaps with the requirements of PRC-004-6. We recommend that this standard be modified to specifically exclude any components already included under PRC-004-6 . In short, it is our opinion that PRC-030-1 should only apply to those event types not covered by PRC-004-6.

Thus, ACES recommends the following changes to Section 4:

4.1 Functional Entities:

4.1.1 Generator Owner (GO)

4.2 Facilities:

4.2.1 Inverter-Based Resource (IBR) meeting the registration criteria for either a Category 1 or Category 2 GO, with the following exclusions:

4.2.1.1 Protection Systems

4.2.1.2 Special Protection Systems (SPS)

4.2.1.3 Remedial Action Schemes (RAS)

4.2.1.4 Underfrequency Load Shedding (UFLS) that is intended to trip one or more BES Elements

4.2.1.5 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

- Additionally, we at ACES have concerns with the timelines specified in Requirements R3 and R4. Requiring the GO to collect data and analyze an event within 30 calendar days and 45 calendar days respectively is much more stringent than identifying and analyzing similar event types under PRC-004-6 Requirements R1, R2, and R3 (i.e., 120 calendar days). We believe these shortened timelines are overly burdensome to the GO and should be aligned with PRC-004-6.
- Moreover, Requirement R3 does not apply any constraints for how long the BA, RC, or TO have to request the data from the GO. Is the GO expected to store and maintain all data for all applicable IBRs for an indefinite period of time? As the BA, RC, and TO already have the ability to request data from the GO under Reliability Standards IRO-010 and TOP-003, we recommend that Requirement R3 and Requirement Part 4.3 be struck from PRC-030-1.
- Lastly, it is the opinion of ACES that Requirement R5 should be modified such that it only applies when an issue is identified after performing the analysis required by R4. We recommend the following language:

“Each Generator Owner that identifies a performance issue under Requirement R4 shall, within 45 days of completing the analysis, develop a Corrective Action Plan (CAP) for correcting the identified issue. The CAP shall include other applicable facilities owned by the Generator Owner as identified in Requirement R4 Part 4.2 that utilize the same equipment that caused the performance issue."

Thank you for the opportunity to comment.

ODEC has the following additional comments:

- In ODEC's opinion, adding additional PRC Reliability Standards that are similar to existing standards creates uncertainty and confusion as to which standards apply to which resource types. We recommend either creating a new category or subcategory of named "IBR" specific standards. Please see the following 2 different examples of potential updates to the NERC Standards Numbering System:
    - New Topic Area
        - IBR-001-1
    - New sub-category
        - PRC-004-IBR-1
- ODEC believes that either PRC-004 or PRC-030 should apply to IBRs, but not both. We recommend exempting IBRs from PRC-004 and incorporating any applicable PRC-004-6 requirements into PRC-030-1.

Likes 0	

Dislikes 0	
Response	
Thank you for the comment, the facilities in section 4.2 of the latest draft have been updated as "BES Inverter-Based Resources (IBR)".	

End of Report

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reminder

Standards Announcement

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

Formal Comment Period Open through April 18, 2024
Ballot Pools Forming through April 3, 2024

Now Available

The 25-day formal comment period for draft one of **PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation**, is open through **8 p.m. Eastern, Thursday, April 18, 2024**.

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.

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.

Ballot Pools
Ballot pools are being formed through 8 p.m. Eastern, April 3, 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 standard and implementation plan, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **April 9 – 18, 2024**.

For 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 470-755-0346. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues observer list” in the Description Box.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reminder

Standards Announcement

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

Initial Ballots and Non-binding Poll Open through April 18, 2024

Now Available

Initial ballots for draft one of **PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Thursday, April 18, 2024**.

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 Standards Developer, Josh Blume (via email) or at 470-755-0346. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues 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

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

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

Formal Comment Period Open through April 18, 2024
Ballot Pools Forming through April 3, 2024

Now Available

A 25-day formal comment period for draft one of **PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation,** is open through **8 p.m. Eastern, Thursday, April 18, 2024.**

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.

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.

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Wednesday, April 3, 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 standard and implementation plan, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **April 9 – 18, 2024**.

For 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 470-755-0346. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues 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

Ballot Results

Comment: View Comment Results
Ballot Name: 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues PRC-030-1 IN 1 ST
Voting Start Date: 4/9/2024 12:01:00 AM
Voting End Date: 4/18/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 257
Total Ballot Pool: 277
Quorum: 92.78
Quorum Established Date: 4/18/2024 1:05:16 PM
Weighted Segment Value: 21.19

Actions

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	76	1	6	0.102	53	0.898	0	11	6
Segment: 2	8	0.5	3	0.3	2	0.2	0	2	1
Segment: 3	60	1	9	0.164	46	0.836	1	2	2
Segment: 4	13	0.9	2	0.2	7	0.7	0	3	1
Segment: 5	69	1	7	0.125	49	0.875	0	9	4
Segment: 6	44	1	5	0.139	31	0.861	0	3	5
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: 10	7	0.4	2	0.2	2	0.2	0	2	1
Totals:	277	5.8	34	1.229	190	4.571	1	32	20

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
5	AEP	Thomas Foltz		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Third-Party Comments
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
1	Manitoba Hydro	Nazra Gladu		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party Comments
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	SaskPower	Wayne		None	N/A

		Guttormson		
5	Xcel Energy, Inc.	Gerry Huitt	Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	Negative	Third-Party Comments
5	Manitoba Hydro	Kristy-Lee Young	Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer	Negative	Third-Party Comments
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray	Negative	Comments Submitted
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy	Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman	Negative	Third-Party Comments
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson	None	N/A
1	Dairyland Power Cooperative	Karrie Schuldt	Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	Third-Party Comments
1	Black Hills Corporation	Micah Runner	Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke	None	N/A
10	Midwest Reliability Organization	Mark Flanary	Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells	Negative	Third-Party Comments
1	Sunflower Electric Power Corporation	Paul Mehlhaff	None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost	Negative	Third-Party Comments
5	Avista - Avista Corporation	Glen Farmer	Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Anna Salmon	Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer	Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry	Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith	Negative	Comments Submitted
6	AEP	Mathew Miller	Negative	Comments Submitted
5	PSEG Nuclear LLC	Tim Kucey	Negative	Third-Party Comments
3	Sempra - San Diego Gas and Electric	Bryan Bennett	Negative	Third-Party Comments
6	APS - Arizona Public Service Co.	Marcus Bortman	Negative	Comments Submitted

3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	Third-Party Comments
1	Orlando Utilities Commission	Aaron Staley		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Negative	Third-Party Comments
5	American Municipal Power	Amy Ritts		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
6	Powerex Corporation	Raj Hundal		Negative	Third-Party Comments
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Negative	Third-Party Comments
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A

6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Third-Party Comments
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Negative	Comments Submitted
4	DTE Energy	Patricia Ireland		Negative	Comments Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
6	Manitoba Hydro	Kelly Bertholet		Negative	Comments Submitted
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Third-Party Comments
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Abstain	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
3	New York Power Authority	David Rivera		Negative	Third-Party Comments
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
					Comments

5	Decatur Energy Center LLC	Megan Melham		Negative	Submitted
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Third-Party Comments
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
6	Western Area Power Administration	Jennifer Neville		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A
6	Great River Energy	Brian Meloy		None	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted
5	NextEra Energy	Richard Vendetti		Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	Constellation	Alison MacKellar		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Third-Party Comments
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Affirmative	N/A
1	Salt River Project	Matthew Jaramilla	Israel Perez	Negative	Comments Submitted
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A

6	Duke Energy	John Sturgeon		Negative	Comments Submitted
1	Eversource Energy	Joshua London		Abstain	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Third-Party Comments
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Negative	No Comment Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
3	Entergy	James Keele		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Abstain	N/A
1	New York Power Authority	Daniel Valle		Negative	Third-Party Comments
1	Duke Energy	Katherine Street		Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
6	Invenergy LLC	Colin Chilcoat		Negative	Comments Submitted
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Third-Party Comments
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments

1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Negative	Third-Party Comments
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	Comments Submitted
10	New York State Reliability Council	Wesley Yeomans		None	N/A
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
10	ReliabilityFirst	Tyler Schwendiman		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	Invenergy LLC	Rhonda Jones		None	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Third-Party Comments
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Comments Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Negative	Third-Party

					Comments
6	Austin Energy	Imane Mrini		None	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Abstain	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Third-Party Comments
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
4	Austin Energy	Tony Hua		Abstain	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	Comments Submitted
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Third-Party Comments
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Abstain	N/A
2	ISO New England, Inc.	John Pearson		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Abstain	N/A

3	Southern Indiana Gas and Electric Co.	Ryan Snyder	Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons	Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood	Negative	Comments Submitted
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez	Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis	Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong	Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden	Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski	Negative	Comments Submitted
1	National Grid USA	Michael Jones	Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli	None	N/A
3	National Grid USA	Brian Shanahan	Negative	Third-Party Comments
3	Tri-State G and T Association, Inc.	Ryan Walter	Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo	Abstain	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder	Negative	Third-Party Comments
5	Entergy - Entergy Services, Inc.	Gail Golden	Negative	Comments Submitted
5	Enel Green Power	Natalie Johnson	Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Kati Barr	Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker	Affirmative	N/A
5	New York Power Authority	Zahid Qayyum	Negative	Third-Party Comments
3	Seminole Electric Cooperative, Inc.	Marc Sedor	None	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu	Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley	Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood	Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder	Negative	Comments Submitted
1	Tennessee Valley Authority	David Plumb	Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen	Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke	Negative	Comments Submitted
5	California Department of Water Resources	ASM Mostafa	Abstain	N/A

4	Western Power Pool	Kevin Conway		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
1	JEA	Joseph McClung		Negative	Third-Party Comments
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
3	AES - Indianapolis Power and Light Co.	Leo Bernier		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
3	JEA	Marilyn Williams		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	JEA	John Babik		Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	Negative	Third-Party Comments
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Third-Party Comments
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Negative	Third-Party Comments
1	Sho-Me Power Electric Cooperative	Olivia Olson		None	N/A
1	Lincoln Electric System	Josh Johnson		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
3	Lincoln Electric System	Sam Christensen		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Third-Party Comments
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted

6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	Third-Party Comments
5	OTP - Otter Tail Power Company	Stacy Wahlund	Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson	Negative	Third-Party Comments
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads	Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas	Negative	Third-Party Comments
3	Central Electric Power Cooperative (Missouri)	Adam Weber	Negative	Third-Party Comments
5	BC Hydro and Power Authority	Quincy Wang	Negative	Comments Submitted
3	Los Angeles Department of Water and Power	Fausto Serratos	Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu	Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer	None	N/A

Ballot Results

Comment: [View Comment Results](#)
Ballot Name: 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Implementation Plan IN 1 OT
Voting Start Date: 4/9/2024 12:01:00 AM
Voting End Date: 4/18/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 258
Total Ballot Pool: 278
Quorum: 92.81
Quorum Established Date: 4/18/2024 12:34:11 PM
Weighted Segment Value: 30.6

Actions

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	76	1	9	0.155	49	0.845	0	12	6
Segment: 2	8	0.4	4	0.4	0	0	0	3	1
Segment: 3	60	1	11	0.208	42	0.792	0	5	2
Segment: 4	13	0.9	2	0.2	7	0.7	0	3	1
Segment: 5	70	1	12	0.222	42	0.778	0	11	5
Segment: 6	44	1	8	0.229	27	0.771	0	5	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: 10	7	0.3	3	0.3	0	0	0	3	1
Totals:	278	5.6	49	1.714	167	3.886	0	42	20

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
5	AEP	Thomas Foltz		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Third-Party Comments
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
1	Manitoba Hydro	Nazra Gladu		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party Comments
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	SaskPower	Wayne		None	N/A

		Guttormson		
5	Xcel Energy, Inc.	Gerry Huitt	Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	Negative	Third-Party Comments
5	Manitoba Hydro	Kristy-Lee Young	Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer	Negative	Third-Party Comments
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray	Negative	Comments Submitted
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy	Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman	Negative	Third-Party Comments
1	Dairyland Power Cooperative	Karrie Schuldt	Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	Third-Party Comments
1	Black Hills Corporation	Micah Runner	Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke	Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary	Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells	Negative	Third-Party Comments
1	Sunflower Electric Power Corporation	Paul Mehlhaff	None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost	Negative	Third-Party Comments
5	Avista - Avista Corporation	Glen Farmer	Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Anna Salmon	Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer	Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry	Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith	Negative	Comments Submitted
6	AEP	Mathew Miller	Negative	Comments Submitted
5	PSEG Nuclear LLC	Tim Kucey	Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett	Negative	Third-Party Comments
6	APS - Arizona Public Service Co.	Marcus Bortman	Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez	Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley	None	N/A
				Comments

5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	Third-Party Comments
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Negative	Third-Party Comments
5	American Municipal Power	Amy Ritts		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Third-Party Comments

1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Negative	Comments Submitted
4	DTE Energy	Patricia Ireland		Negative	Comments Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
6	Manitoba Hydro	Kelly Bertholet		Negative	Comments Submitted
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Third-Party Comments
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
3	New York Power Authority	David Rivera		Negative	Third-Party Comments
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		None	N/A
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Third-Party Comments

5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
6	Western Area Power Administration	Jennifer Neville		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A
6	Great River Energy	Brian Meloy		None	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted
5	NextEra Energy	Richard Vendetti		Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	Constellation	Alison MacKellar		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Third-Party Comments
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Affirmative	N/A
1	Salt River Project	Matthew Jaramilla	Israel Perez	Negative	Comments Submitted
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
1	Eversource Energy	Joshua London		Abstain	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Third-Party Comments
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Abstain	N/A

5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
3	Entergy	James Keele		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Abstain	N/A
1	New York Power Authority	Daniel Valle		Negative	Third-Party Comments
1	Duke Energy	Katherine Street		Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Third-Party Comments
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments

5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
10	ReliabilityFirst	Tyler Schwendiman		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	Invenergy LLC	Rhonda Jones		None	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
5	Grid Strategies LLC	Michael Goggin		None	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Third-Party Comments
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Negative	Third-Party Comments
6	Austin Energy	Imane Mrini		None	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Third-Party Comments
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
4	Austin Energy	Tony Hua		Abstain	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A

5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
5	Tennessee Valley Authority	Darren Boehm		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Third-Party Comments
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Abstain	N/A
2	ISO New England, Inc.	John Pearson		Abstain	N/A
6	Bonneville Power Administration	Tanner Brier		Abstain	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		None	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo		Abstain	N/A

3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
5	Enel Green Power	Natalie Johnson		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	California Department of Water Resources	ASM Mostafa		Abstain	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
1	JEA	Joseph McClung		Negative	Third-Party Comments
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
3	AES - Indianapolis Power and Light Co.	Leo Bernier		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
3	JEA	Marilyn Williams		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	JEA	John Babik		Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments

5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	Negative	Third-Party Comments
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Third-Party Comments
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Negative	Third-Party Comments
1	Sho-Me Power Electric Cooperative	Olivia Olson		None	N/A
1	Lincoln Electric System	Josh Johnson		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		Negative	Comments Submitted
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Third-Party Comments
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A

[redacted]

Ballot Results

Ballot Name: 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues PRC-030-1 | Non-binding Poll IN 1 NB
Voting Start Date: 4/9/2024 12:01:00 AM
Voting End Date: 4/18/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 236
Total Ballot Pool: 262
Quorum: 90.08
Quorum Established Date: 4/18/2024 2:14:32 PM
Weighted Segment Value: 13.11

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	73	1	5	0.1	45	0.9	16	7
Segment: 2	7	0.3	1	0.1	2	0.2	2	2
Segment: 3	56	1	5	0.111	40	0.889	8	3
Segment: 4	13	0.9	1	0.1	8	0.8	3	1
Segment: 5	66	1	5	0.111	40	0.889	15	6
Segment: 6	41	1	4	0.143	24	0.857	6	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: 10	6	0.3	3	0.3	0	0	3	0
Totals:	262	5.5	24	0.965	159	4.535	53	26

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
5	AEP	Thomas Foltz		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		None	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		None	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Comments Submitted

1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke		None	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Anna Salmon		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
6	AEP	Mathew Miller		Negative	Comments Submitted
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted

4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
6	Powerex Corporation	Raj Hundal		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Comments Submitted
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras Sr		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Negative	Comments Submitted
4	DTE Energy	Patricia Ireland		Negative	Comments Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Negative	Comments Submitted

3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Abstain	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
3	New York Power Authority	David Rivera		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
5	Decatur Energy Center LLC	Megan Melham		Negative	Comments Submitted
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		None	N/A
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
6	Western Area Power Administration	Jennifer Neville		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A
6	Great River Energy	Brian Meloy		None	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted
					Comments

6	Salt River Project	Timothy Singh	Israel Perez	Negative	Submitted
5	NextEra Energy	Richard Vendetti		Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	Constellation	Alison MacKellar		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Abstain	N/A
1	Salt River Project	Matthew Jaramilla	Israel Perez	Negative	Comments Submitted
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
1	Eversource Energy	Joshua London		Abstain	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
3	Entergy	James Keele		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Abstain	N/A
1	New York Power Authority	Daniel Valle		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Comments Submitted
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
5	National Grid USA	Robin Berry		Negative	Comments Submitted

5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
6	Muscatine Power and Water	Nicholas Burns		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	Comments Submitted
1	Muscatine Power and Water	Andrew Kurriger		Negative	Comments Submitted
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Comments Submitted
10	ReliabilityFirst	Tyler Schwendiman		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
5	Grid Strategies LLC	Michael Goggin		None	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A

1	Arkansas Electric Cooperative Corporation	Emily Corley		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Abstain	N/A
6	Austin Energy	Imane Mrini		None	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
4	Austin Energy	Tony Hua		Abstain	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	Comments Submitted
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
5	Tennessee Valley Authority	Darren Boehm		None	N/A
6	New York Power Authority	Shelly Dineen		Negative	Comments Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
					Comments

4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Submitted
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Abstain	N/A
2	ISO New England, Inc.	John Pearson		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Abstain	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		None	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo		Abstain	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
5	Enel Green Power	Natalie Johnson		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted

5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Ken Habgood		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	California Department of Water Resources	ASM Mostafa		Abstain	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
1	JEA	Joseph McClung		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
3	AES - Indianapolis Power and Light Co.	Leo Bernier		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Comments Submitted
3	JEA	Marilyn Williams		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	JEA	John Babik		Negative	Comments Submitted
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Olivia Olson		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Comments

				Submitted
3	M and A Electric Power Cooperative	Gary Dollins	Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth	Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund	Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads	Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber	Negative	Comments Submitted
5	BC Hydro and Power Authority	Quincy Wang	Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu	Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry	Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer	None	N/A

[redacted]

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-030-1 is posted for a 34-day formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 25, 2023
SAR posted for comment	February 22, 2023 – March 23, 2023
25-day formal or informal comment period with ballot	March 25, 2024 – April 18, 2024

Anticipated Actions	Date
34-day formal or informal comment period with additional ballot	June 7, 2024 – July 10, 2024
05-day final ballot	TBD
Board adoption	August 14 - 15, 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:** Unexpected Inverter-Based Resource Event Mitigation
2. **Number:** PRC-030-1
3. **Purpose:** Identify, analyze, and mitigate unexpected inverter-based resource (IBR) change of power output.
4. **Applicability:**
   - **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[1] (IBR)
5. **Effective Date:** See Implementation Plan for PRC-030-1

[1] 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.

B. Requirements and Measures

R1. Each applicable Generator Owner shall implement a documented process to identify changes in active power output that are the greater of 10% of the plant's gross nameplate rating or 20 MW, and occurring during a period that is no longer than 4 seconds. Changes in active power for the following are excluded: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- Changes associated with intermittent primary energy source[2] availability;
- Resource dispatch, resource ramping, planned outages, or planned resource testing; or
- Loss of Transmission Provider's interconnection facilities.

M1. Each applicable Generator Owner shall have evidence which includes but is not limited to: (1) the documented process for detecting changes in output as described in Requirement R1, (2) evidence to demonstrate implementation of its documented process, (3) actual data recordings, and (4) identification of gross nameplate rating.

R2. Each applicable Generator Owner, within 90 calendar days of identifying an active power change event pursuant to Requirement R1 or following a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the inverter-based resource(s) active power output, shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determination of the root cause(s) of change(s) in active power output;

2.1.2. Documentation of the facility's Ride-through performance including reactive power response during the event;

2.1.3. Assessment of any performance issues identified and if corrective actions are needed; and

2.1.4. Determination of the susceptibility of its other inverter-based resource facilities to similar events.

2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator.

M2. Each applicable Generator Owner shall have dated documentation of the required analysis developed in accordance with Requirement R2. Evidence may include, but is not limited to: (1) an analysis report, (2) actual data recordings or derivations, (3)

[2] Examples include changes in wind, solar irradiance.

documents describing the device specification and device configuration or settings, and (4) plant configuration.

R3. If performance issues and corrective actions were identified in Requirement R2 Part 2.1.3, each applicable Generator Owner shall, within 60 calendar days of completing the analysis in Requirement R2, develop one of the following and provide it to the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- A Corrective Action Plan (CAP) for the identified inverter-based resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R2 Part 2.1.3; or
- A technical justification that addresses why corrective actions will not be applied nor implemented.

M3. Each applicable Generator Owner shall have dated evidence (electronic or hardcopy format) that demonstrates it developed a CAP or a technical justification, and evidence of transmittal to the Reliability Coordinator, Balancing Authority, and Transmission Operator in accordance with Requirement R3.

R4. Each applicable Generator Owner shall, for each of its Corrective Action Plans developed pursuant to Requirement R3: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

4.1. Implement the CAP;

4.2. Update the CAP if actions or timetables change; and

4.3. Notify each applicable Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

M4. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, communication with equipment manufacturers, and communication with each applicable Reliability Coordinator that documents the implementation, updating, or completion of a CAP in accordance with Requirement R3.

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 shall keep data or evidence of Requirement R1, and R2, Measure M1, and M2 for 36 calendar months following the completion of each Requirement.
- The Generator Owner shall retain evidence of Requirement R3, Measure M3, including any supporting analysis per Requirements R2 and R3, for a minimum of 36 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.
- The Generator Owner shall retain evidence of Requirement R4, Measure M4 for a minimum of 36 calendar months following completion of each CAP.

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 responsible entity failed to implement a documented process to identify changes in active power output in accordance with Requirement R1.
R2.	The responsible entity performed an analysis in accordance with Requirement R2, but in more than 90 calendar days but less than 120 calendar days of first identifying an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 120 or more calendar days but less than 150 calendar days of first identifying an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 150 or more calendar days but less than 180 calendar days of first identifying an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 or Part 2.1.4. OR The responsible entity failed to provide the analysis results from the requesting entity in accordance with Requirement R2, Part 2.2.	The responsible entity developed an analysis in accordance with Requirement R2, but in 180 calendar days or more of first identifying an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 and Part 2.1.4. OR The responsible entity failed to document the facility's ride-through performance in accordance with Requirement R2, Part 2.1.2 OR

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				The responsible entity failed to determine the susceptibility of other inverter-based resource facilities in accordance with Requirement R2, Part 2.1.3.
R3.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 60 days, but provided it within 90 days.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 90 days, but provided it within 120 days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 120 days, but provided it within 150 days OR The developed CAP did not include corrective actions for other facilities owned by the Generator Owners as identified in Requirement R2 Part 2.1.3, if necessary. OR The developed CAP or technical justification was not provided to the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented, within 150 calendar days.
R4.	The responsible entity implemented, but failed to	N/A	N/A	The responsible entity failed to implement a CAP in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	update a CAP, when actions or timetables changed, in accordance with Requirement R4.			accordance with Requirement R4.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan.

Version History

Version	Date	Action	Change Tracking
Initial Draft	**02/06/2024**	**Draft**	
Second Draft	**06/07/2024**	**Draft**	

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-030-1 is posted for a 34-day formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 25, 2023
SAR posted for comment	February 22, 2023 – March 23, 2023
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None

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2. **Number:** PRC-030-1
3. **Purpose:** Identify, analyze, and mitigate unexpected inverter-based resource (IBR) change of power output.
4. **Applicability:**
    - **4.1. Functional Entities:**
        - **4.1.1.** Generator Owner that owns equipment as identified in section 4.2
    - **4.2. Facilities:**
        - **4.2.1.** ~~Bulk Power System (BPS)~~ BES inverter-based resources[1] (IBR)
5. **Effective Date:** See Implementation Plan for PRC-030-1

[1] 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.

B. Requirements and Measures

R1. Each applicable Generator Owner shall ~~have~~ implement a documented process to identify ~~unexpected~~ changes~~[1]~~ in active power output ~~occurring within a two-second period and is~~that are the greater of ~~either 20~~10% of the plant's gross nameplate rating~~,~~ or 20 ~~MVA~~MW, and occurring during a period that is no longer than 4 seconds. Changes in active power for the following are excluded: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- Changes associated with intermittent primary energy source[2] availability;
- Resource dispatch, resource ramping, planned outages, or planned resource testing; or
- Loss of Transmission Provider's interconnection facilities.

M1. Each applicable Generator Owner shall have evidence which ~~may~~ includes but is not limited to: (1) ~~a~~the documented process for detecting ~~unexpected~~ changes in output as described in Requirement R1, (2) evidence to demonstrate implementation of its documented process, (3) actual data recordings, and (~~3~~4) identification of gross nameplate rating.

~~**R2.** Each applicable Generator Owner shall implement its process established in Requirement R1 to identify unexpected changes in power output. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~**M2.** Acceptable evidence of implementation may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the applicable Generator Owner implemented its process established in Requirement R1.~~

~~**R3.** Each applicable Generator Owner shall provide data when requested from its Balancing Authority, Reliability Coordinator, or Transmission Operator regarding IBR responses during an identified system level event within 30 calendar days of the receipt of the request. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~Each applicable Generator Owner shall have evidence as specified in Requirement R3 which may include, but is not limited to, dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.~~

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~~[1] Unexpected changes in power output includes any change of generation that is not attributed to factors such as weather patterns, change of wind, change in irradiance, curtailment, ramping, planned outage, planned testing, or the loss of a Transmission Line connecting the IBR generators.~~

[2] Examples include changes in wind, solar irradiance.

~~R4.~~**R2.** Each applicable Generator Owner~~ shall analyze its IBRs performance~~, within ~~45~~90 calendar days of ~~either the event identified~~identifying an active power change event pursuant to Requirement R1~~2~~ or following ~~receipt of~~ a request~~ pursuant to Requirement R3. The analysis shall include all of the following~~ from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the inverter-based resource(s) active power output, shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

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2.1. Analyze its IBR facility performance during the event, including:

~~4.1.0.~~**2.1.1.** ~~The~~Determination of the root cause(s) of ~~unexpected~~ change(s) in active power output;

~~4.2. The applicability to its other IBR facilities that could be affected by the same cause of unexpected change(s) in power output; and~~

2.1.2. Documentation of the facility's Ride-through performance including reactive power response during the event;

2.1.3. Assessment of any performance issues identified and if corrective actions are needed; and

2.1.4. Determination of the susceptibility of its other inverter-based resource facilities to similar events.

~~4.3.~~**2.2.** ~~Notification to each~~Upon request, provide the analysis results to the requesting applicable ~~Balancing Authority,~~ Reliability Coordinator, Balancing Authority, or Transmission Operator~~ of the analysis results~~.

~~M4.~~**M2.** Each applicable Generator Owner shall have dated ~~analysis~~ documentation~~,~~ of the required analysis developed in accordance with ~~Requirements R4~~Requirement R2. Evidence may include, but is not limited to: (1) an analysis report, (2) actual data recordings or derivations, (3) documents describing the device specification and device configuration or settings, and (4) plant configuration.

~~R5.~~**R3.** ~~Each~~If performance issues and corrective actions were identified in Requirement R2 Part 2.1.3, each applicable Generator Owner shall, within ~~45~~60 calendar days of completing the analysis in Requirement ~~R4~~R2, develop one of the following and provide it to ~~each~~the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- ~~5.1.~~ A Corrective Action Plan (CAP) for the identified ~~Inverter-Based Resource~~inverter-based resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement ~~R4~~R2 Part ~~4.2~~2.1.3; or

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- ~~5.2.~~ A technical justification that addresses why corrective actions will not be applied nor implemented.

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~~M5.~~M3. Each applicable Generator Owner shall have dated evidence (electronic or hardcopy format) that demonstrates it developed a CAP or a technical justification, and evidence of transmittal to the Reliability Coordinator, Balancing Authority, and Transmission Operator in accordance with Requirement ~~R5~~R3.

~~R2.~~R4. Each applicable Generator Owner shall, for each of its Corrective Action Plans developed pursuant to Requirement ~~R5~~R3: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

~~6.1.~~4.1. Implement the CAP;

~~6.2.~~4.2. Update the CAP if actions or timetables change; and

~~6.3.~~4.3. Notify each applicable Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

~~M6.~~M4. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, communication with equipment manufacturers, and communication with each applicable Reliability Coordinator that documents the implementation, updating, or completion of a CAP in accordance with Requirement ~~R5~~R3.

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 shall keep data or evidence of Requirement R1, and R2, ~~and R3,~~ Measure M1, and M2~~, and M3~~ for ~~12~~36 calendar months following the completion of each Requirement.
- The Generator Owner shall retain evidence of Requirement ~~R4~~R3, Measure ~~M4~~M3, including any supporting analysis per Requirements R2 and R3, for a minimum of ~~12~~36 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.
- The Generator Owner shall retain evidence of Requirement ~~R6~~R4, Measure ~~M6~~M4 for a minimum of ~~12~~36 calendar months following completion of each CAP.

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 responsible entity failed to ~~have~~ implement a documented process to identify ~~unexpected~~ changes in active power output in accordance with Requirement R1.
~~**R2.**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The responsible entity failed to implement the process established in accordance with Requirement R1.~~
~~**R3.**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The responsible entity failed to provide data when requested from its Balancing Authority, Reliability Coordinator, or Transmission Operator.~~
~~R4~~R2.	The responsible entity performed an analysis in accordance with Requirement ~~R4~~R2, but in more than ~~45~~90 calendar days but less than ~~60~~120 calendar days of first identifying an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement ~~R4~~R2, but in ~~60~~120 or more calendar days but less than ~~90~~150 calendar days of first identifying an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement ~~R4~~R2, but in ~~90~~150 or more calendar days but less than ~~120~~180 calendar days of first identifying an event or receiving a request. OR	The responsible entity developed an ~~evaluation~~analysis in accordance with Requirement ~~R4~~R2, but in ~~120~~180 calendar days or more of first identifying an event or receiving a request. OR

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R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			The responsible entity performed the analysis in Requirement ~~R4,~~R2 but failed to address ~~one of the Parts 4.1 through Parts 4.3.~~Part 2.1.1 or Part 2.1.4. OR The responsible entity failed to provide the analysis results from the requesting entity in accordance with Requirement R2, Part 2.2.	The responsible entity performed the analysis in Requirement ~~R4,~~R2 but failed to address ~~two or more of the Parts 4.1 through Parts 4.3~~Part 2.1.1 and Part 2.1.4. OR The responsible entity failed to document the facility's ride-through performance in accordance with Requirement R2, Part 2.1.2 OR The responsible entity failed to ~~develop an evaluation~~determine the susceptibility of other inverter-based resource facilities in accordance with Requirement ~~R4~~R2, Part 2.1.3.
~~R5~~R3.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within ~~45~~60 days, but provided it within ~~60~~90 days.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within ~~60~~90 days, but provided it within ~~90~~120 days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within ~~90~~120 days, but provided it within ~~120~~150 days	The responsible entity ~~developed~~failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented, ~~but in 120~~within 150 calendar days ~~or more~~.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The developed CAP did not include corrective actions for other facilities owned by the ~~GO~~Generator Owners as identified in ~~R4.2~~Requirement R2 Part 2.1.3, if necessary. OR The developed CAP or technical justification was not provided to the applicable ~~RC~~Reliability Coordinator, Balancing Authority, and Transmission Operator.	~~OR~~ ~~The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented.~~
~~R6~~R4.	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement ~~R6~~R4.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement ~~R6~~R4.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan.

Version History

Version	Date	Action	Change Tracking
Initial Draft	**02/06/2024**	**Draft**	
Second Draft	**06/07/2024**	**Draft**	

Implementation Plan

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1

Applicable Standard(s)

- PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation

Requested Retirement(s)

- None

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
- PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Generating Resources

Applicable Entities

- Generator Owner (GO)

Background

Multiple NERC disturbance reports,[1] including the Odessa disturbance report,[2] identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that this undesired performance can pose. IBRs may trip for many different reasons, may cease current injection due to inverter controls, or may have unwanted plant-level controller interactions. These types of issues have been extensively documented in the NERC reports. The resulting unexpected and unwarranted loss of generation poses a significant risk to BPS reliability. Project 2023-02 was initiated to address the reliability-related need and benefit by requiring analysis and mitigation of unexpected or unwarranted protection and control operations from inverter-based resources following the identification of such a performance issue.

1 https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx
2 https://www.nerc.com/pa/rrm/ea/Pages/May-June-2021-Odessa-Disturbance.aspx

After Project 2023-02 was initiated, FERC issued Order No. 901,[3] which directs the development of new or modified reliability standards, including 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[4]. Within the work plan, NERC identified three active Standards Development Projects that would need to be filed for regulatory approval with FERC November 4, 2024. These projects include 2020-02 Modifications to PRC-024 (Generation Ride Through),[5] 2021-04 Modifications to PRC-002-2,[6] and 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues.[7]

General Considerations

The requested implementation timeline allows for ample time for entities to draft and implement their process. The information required for standard compliance is currently available to Generator Owners.

Effective Date

The effective date for the proposed Reliability Standard is provided below.

Standard PRC-030-1

Where approval by an applicable governmental authority is required, Reliability Standard PRC-030-1 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, Reliability Standard PRC-030-1 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.

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[3] *Reliability Standards to Address Inverter-Based Resources,* Order No.901, 185 FERC ¶ 61,042 (2023); https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false
[4] *See Informational Filing of the N. Am. Elec. Reliability Corp. Regarding the Development of Reliability Standards Responsive to Order No. 901.*, Docket No. RM22-12-000 (January 18, 2024).
[5] *See* NERC Standards Development Project page for Project 2002-02; https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx
[6] *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
[7] *See* NERC Standards Development Project page for Project 2023-02; https://www.nerc.com/pa/Stand/Pages/Project-2023-02-Performance-of-IBRs.aspx

Implementation Plan

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1

Applicable Standard(s)

PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation

Requested Retirement(s)

None

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Generating Resources

Applicable Entities

Generator Owner (GO)

Background

Multiple NERC disturbance reports,[1] including the Odessa disturbance report,[2] identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that this undesired performance can pose. IBRs may trip for many different reasons, may cease current injection due to inverter controls, or may have unwanted plant-level controller interactions. These types of issues have been extensively documented in the NERC reports. The resulting unexpected and unwarranted loss of generation poses a significant risk to BPS reliability. Project 2023-02 was initiated to address the reliability-related need and benefit by requiring analysis and mitigation of unexpected or unwarranted protection and control operations from inverter-based resources following the identification of such a performance issue.

[1] https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx
[2] https://www.nerc.com/pa/rrm/ea/Pages/May-June-2021-Odessa-Disturbance.aspx

After Project 2023-02 was ~~underway~~initiated, FERC issued Order No. ~~Order~~ 901~~[1]that~~ ,[3] which directs the development of new or modified reliability standards, including 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~~[2]~~[4]. Within the work plan, NERC identified three active Standards Development Projects that would need to be filed for regulatory approval with FERC November ~~4th~~4, 2024. These projects include 2020-02 Modifications to PRC-024 (Generation Ride Through)~~[3]~~,[5] 2021-04 Modifications to PRC-002-2~~[4]~~,[6] and 2023-02 Analysis and Mitigation of BES Inverter-Based ~~Resources~~Resource Performance Issues~~[5]~~.[7]

General Considerations

The ~~key development for applicable Functional Entities is a process to capture change in power events for IBR resources. The~~ requested implementation timeline allows for ample time for entities to draft and implement their process. The information required for ~~Standard~~standard compliance is currently available to Generator Owners.

Effective Date

The effective date for the proposed Reliability Standard is provided below.

Standard PRC-030-1

~~[1] 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] *Reliability Standards to Address Inverter-Based Resources*, Order No.901, 185 FERC ¶ 61,042 (2023); https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false

~~[2]~~[4] *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;~~ *Informational Filing of the N. Am. Elec. Reliability Corp. Regarding the Development of Reliability Standards Responsive to Order No. 901.*, Docket No. RM22-12-000 (January ~~17~~18, 2024).

~~[3] 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 2002-02; https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx

~~[4] 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 2021-04; https://www.nerc.com/pa/Stand/Pages/Project-2021-04-Modifications-to-PRC-002-2.aspx

~~[5] See NERC Standards Development Project page for Project 2023-02; https://www.nerc.com/pa/Stand/Pages/Project-2023-02-Performance-of-IBRs.aspx~~

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

Where approval by an ~~Applicable Governmental Authority~~applicable governmental authority is required, Reliability Standard PRC-030-1 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, Reliability Standard PRC-030-1 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.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Technical Rationale

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1 | June 2024

PRC-030-1 – Unexpected Inverter-Based Resource Event Mitigation

Rationale for Applicability Section

The functional entity responsible for identifying, analyzing, and mitigating unexpected Inverter Based Resources (IBR) performance is the Generator Owner (GO). The Generator Operator (GOP) is not included because of the accountability and coordination issues introduced by listing both GO and GOP as responsible functional entities. Further, this standard intentionally did not include requirements for the Balancing Authority (BA), Reliability Coordinator (RC), and Transmission Operator (TOP) because other standards (e.g., EOP-004) place requirements on these entities for system level events.

General rationale

Aligned with the Project 2023-02 Standards Authorization Request (SAR), the Requirements are structured to identify, analyze, and mitigate IBR performance issues. The SAR discusses how a series of NERC disturbance reports have "identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that these pose". [1,2,3,4,5,6,7,8,9] In particular, IBR performance during events has included tripping or momentary cessation that is unexpected, unwarranted, and poses reliability challenges.

Requirement R1 defines how events are to be identified, along with exceptions that should not be identified. Requirement R2 requires analysis of identified events, with specific elements assessed as

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[1] *Odessa Disturbance,* NERC. September 2021.https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf
[2] *2022 Odessa Disturbance,* NERC. Atlanta, GA: December 2022. https://www.nerc.com/comm/RSTC_Reliability_Guidelines/NERC_2022_Odessa_Disturbance_Report%20%281%29.pdf
[3] *900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*, NERC. Atlanta, GA: February 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
[4] *April and May 2018 Fault Induced Solar Photovoltaic Resource Interruption Disturbances Report*, NERC. Atlanta, GA: January 2019. https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf
[5] *Panhandle Wind Disturbance*, NERC. Atlanta, GA: August 2022. https://www.nerc.com/pa/rrm/ea/Documents/Panhandle_Wind_Disturbance_Report.pdf
[6] *Panhandle Wind Disturbance*, NERC. Atlanta, GA: August 2022. https://www.nerc.com/pa/rrm/ea/Documents/Panhandle_Wind_Disturbance_Report.pdf
[7] *1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*, NERC. 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
[8] *San Fernando Disturbance*, NERC. November 2020. https://www.nerc.com/pa/rrm/ea/Documents/San_Fernando_Disturbance_Report.pdf
[9] https://www.iec.ch/conformity-assessment/what-conformity-assessment

described in subparts. Requirement R3 requires a Corrective Action Plan (CAP) or technical justification when corrective actions are needed. Finally, R4 requires mitigation of the performance risk through CAP implementation. The flow of these requirements is summarized in Figure 1.

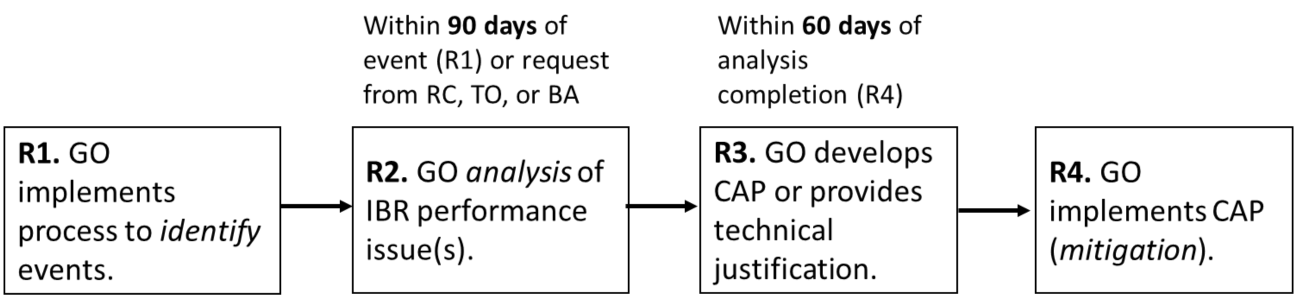

Figure 1.1: Relationship of Requirements in PRC-030-1

The Requirement R1 contains thresholds for identifying events with sudden changes in active power. Figure 1.2 depicts the threshold criteria and logic used in Requirement R1, along with additional details of process flow in Requirement R2.

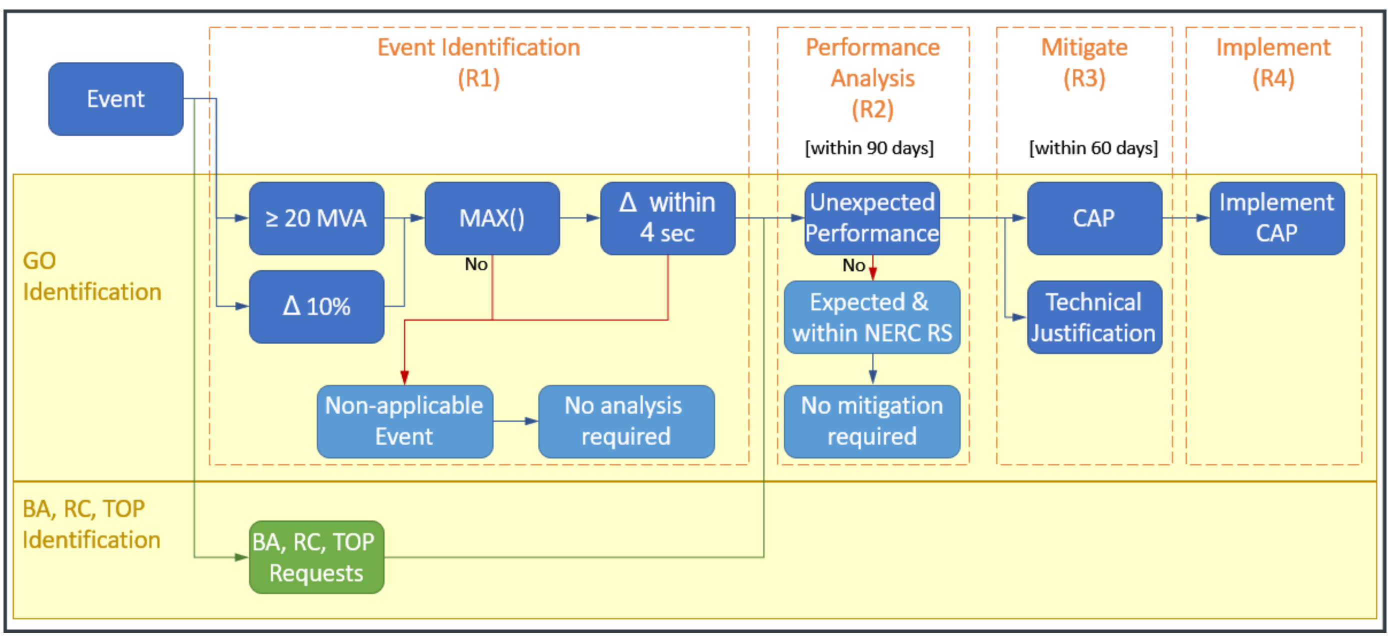

Figure 1.2: PRC-030-1 Flowchart

Rationale for Requirement R1

The intent of Requirement R1 is for the Generator Owner (GO) to implement a documented process to self-identify events that are sufficiently large to warrant an analysis of IBR performance for the identified event.

While the GO should consider both active and reactive power responses when an analysis is required, only active power is used as a threshold to trigger analysis. Active power was selected as the monitored parameter to make feasible implementation across IBR plant designs and backend software system (e.g., SCADA).

Nameplate rating was used as the basis of the change (power or amperes) because it is the common reference in NERC and other industry standards. The IBR continuous rating concept outlined in IEEE 2800-2022 definitions was considered and determined to be a departure from NERC standards approaches to date.

The 10% magnitude of event threshold was chosen to be large enough to screen out small active power changes but low enough to detect events that should be analyzed for reliability purposes. The percent change is mainly intended to address large units where 10% is a significant change, otherwise the 20 MW threshold sets a minimum threshold for event identification. For smaller capacity facilities, the use of only a percent change as the screening criteria would lead to identification of disturbances that are not likely to be significant for analysis.

The intention of the period no longer than four second was to define a sudden change in power, similar to the types of active power loss events described in NERC Disturbance Event reports. The intent is to exclude from review slow power changes expected with normal operations (e.g., variable output from weather, dispatch, planned outages, testing) or expected responses (e.g., loss of interconnection facilities), which were defined as bullet points to Requirement R1.

The various SCADA scan rates in use at ISOs/RTOs as well as NERC standard minimum required scan rates were considered in selecting four seconds. SCADA monitoring is a likely method for monitoring active power changes. Power changes that occur and recover within one scan are not expected to be detected by the Requirement R1 process implemented by GOs. The four seconds was not intended to define the scan period, but only to characterize the change as sudden when considering information on monitoring capabilities across the industry. It should be noted that selecting longer time periods could lead to a need for more sophisticated event screening or may otherwise lead to identification of more invalid events that occur on slower timescales.

The term “changes in active power” encompasses both sudden decreases (i.e., loss of output) and increases (i.e., additional consumption) that may be caused by IBR mis-operations that could affect system reliability. For instance, a battery energy storage system that mis-measures system frequency may unexpectedly enter a charging mode and suddenly increase active power draw.

Photovoltaic (PV) example 1 – qualifying:
PV facility with gross nameplate rating of 220 MW is operating with active output of 80 MW. During a transmission system fault event,[10] the plant exhibits a near instantaneous active power output drop to 50 MW.

[10] The transmission line fault is assumed not to be on the line connecting the IBR to the system, but rather is a fault remote from the IBR.

The change in apparent power in under four seconds is 30 MW, which exceeds 22 MW, the greater of 10% of the plant's gross nameplate (22 MW) or 20 MW. This IBR performance event is required to be captured by the GO's process implemented in Requirement R1.

PV example 2 – non-qualifying:
PV facility with gross nameplate rating of 80 MW is operating with active output of 60 MW. During a transmission line fault event,[1] the plant exhibits a near instantaneous active power output drop to 42 MW.

The change in apparent power in under four seconds is 18 MW, <u>not</u> exceeding 20 MW, the greater of 10% of the plant's gross nameplate rating (8 MW) or 20 MW. This IBR performance event is <u>not</u> required to be captured by the GO's Requirement R1 process.

Battery Energy Storage System (BESS) example 1 – qualifying:
BESS facility with gross nameplate power output rating of 80 MW is operating as a load drawing 50 MW. During a power plant controller ("PPC") malfunction event of the BESS facility, the PPC incorrectly estimates system frequency sending an incorrect frequency response signal causing the plant to exhibit a near instantaneous change in real power to 10 MW injection.

The change in apparent power in under four seconds is 60 MW, which exceeds 20 MW, the greater of 10% of the BESS gross nameplate (8 MW) or 20 MW.
This IBR performance event is required to be captured by the GO's R1 process.

BESS example 2 – non-qualifying:
BESS facility with gross nameplate power output rating of 80 MW is outputting 40 MW. The BESS facility is curtailed by the RC such that the plant exhibits a near instantaneous active power decrease to 15 MW.

The change in apparent power in under four seconds is 25 MW, exceeding 20 MW, the greater of 10% of the plant's gross nameplate rating (8 MW) or 20 MW. However, the change in apparent power is the result of the RC curtailment which is an exempt event per R1. This IBR performance event is <u>not</u> required to be captured by the GO's Requirement R1 process.

Rationale for Requirement R2
Requirement R2 requires analysis of events that meet Requirement R1 thresholds. Requirement R2 also provides an alternative path of event identification by the BA, RC, or TOP. It is anticipated that some events would only be detected by one entity, but the combination of both identification methods would better identify events potentially posing reliability challenges.

Requirement R2 allows 90 days to analyze expected versus actual IBR responses to place an emphasis on diligent resolution, while still allowing enough time to conduct an analysis and identify causes. Ninety days allows adequate time for Generator Owners (GO) to interact with manufacturers and examine capabilities of equipment. This time was chosen to be closer to the PRC-004 timeline of 120 days while recognizing important differences between the application of these standards. PRC-004-4(i) Technical Rationale states "The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed".[11] The PRC-004 timeframe accounts for extreme weather events such as hurricanes that may affect a very large number of Protection Systems for a given responsible entity. The volume of IBR exposed to potential expected operation is anticipated to be lower when compared to Protection Systems and therefore a shorter timeframe is appropriate for PRC-030. The 90-day period starts from the event date for GO-identified performance issues resulting from Requirement R1 or upon request from the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operator (TOP) regarding IBR responses identified during system events.

Requirement R2.1 has subparts to ensure the root cause is identified (R2.1.1); the facility Ride through and reactive power performance is documented (R2.1.2); the issue is assessed and determination whether corrective actions are needed (R2.1.3); and applicability to other similarly designed units is considered (R2.1.4). Collectively, the subparts define the minimum features required as part of an effective analysis. Requirement R2.2 closes the communication loop with BA, RC, and TOP entities, should these entities request analysis results.

Rationale for Requirement R3

Should Requirement R2 determine a need for corrective actions, Requirement R3 requires a CAP or technical justification be developed within 60 calendar days of completing the analysis in Requirement R2, as identified in Part 2.1.3. If R2 did not identify the need for corrective actions, then R3 does not need to be performed.

Resolving the causes of IBR performance issues benefits Buk Power System (BPS) reliability by preventing recurrence. The CAP is an established tool for resolving operational problems. The NERC *Glossary* defines a Corrective Action Plan as, "A list of actions and an associated timetable for implementation to remedy a specific problem." Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the IBR Performance issue cause(s) is identified in Requirement R2 or Requirement R3 requires Generator Owner(s) to develop a CAP or provide a technical justification that addresses why corrective actions will not be applied nor implemented.

This standard recognizes there may be multiple causes for IBR performance issues. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of an IBR performance issues. The 60-calendar day period for developing a CAP or technical justification is established based on industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

[11] Standard PRC-004-4(i) – Protection System Misoperation Identification and Correction. Available at: https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-004-4(i).pdf

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent IBR performance issues from reoccurring, the timetable for executing such actions, and an evaluation of the CAP's applicability to the GO's other IBR including those at other locations. The evaluation of these other IBR with similar designs aims to reduce the risk and the likelihood of similar IBR performance issues in other IBRs. The GO is responsible for determining the extent of its evaluation concerning other IBRs and locations. The evaluation may result in the GO including actions to address IBR at other locations or to provide a technical justification that addresses why corrective actions will not be applied nor implemented.

Acceptable technical justification for not performing corrective actions is expected to primarily have two characteristics:
1) interconnection requirements on IBR performance extending beyond those in place at the time of interconnection; and
2) it would require material modifications/qualified change.

Technical justifications for not performing corrective actions do not relieve the GO from compliance to other standards (i.e., PRC-029-1 Ride-Through) to the extent that other standards are applicable.

Rationale for Requirement R4

Requirement R4 requires that each entity implement the CAP developed in Requirement R3, as applicable, to mitigate deficiencies identified in Requirement R2. In the NERC *Glossary*, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem."

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. If the CAP is changed, the entity must notify the applicable RC(s), TOP(s), or BA(s). The entity must also notify applicable RC(s), TOP(s) or BA(s) when the CAP has been completed. The implementation of a properly developed CAP ensures that causes of unexpected changes in IBR power output are mitigated in a timely manner.

An IBR deficiency may require the RC, TOP, or BA to impose operating restrictions so the system can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions should incentivize the entity to complete the CAP as quickly as possible.

Unofficial Comment Form

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

Do not use this form for submitting comments. Use the [Standards Balloting and Commenting System (SBS)] to submit comments on draft two of **PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation** by **8 p.m. Eastern, Wednesday, July 10, 2024.**

Additional information is available on the [project page]. If you have questions, contact Standards Developer, [Josh Blume] (email), or at 404-446-2593.

Background Information

Multiple NERC disturbance reports have identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that this undesired performance can pose. Project 2023-02 addresses the reliability-related need by requiring analysis and mitigation of unexpected or unwarranted protection and control operations from IBRs. This includes any types of protections and controls that result in abnormal performance issues within the plant, including abnormal performance resulting in anomalous behavior of active power output from the facility during events.

On October 19, 2023, FERC issued Order No. 901, which directed NERC to develop new or modify existing Reliability Standards that include new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. Project 2023-02 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 a waiver allowing formal comment periods to be reduced from 45 days to as few as 25 calendar days, and final ballot periods to be reduced from 10 days to as few as 5 calendar days in order to help meet the FERC- directed deadline.

Questions

1. Does the entity believe there should be any proposed changes in the thresholds in Requirement R1?

   ☐ Yes
   ☐ No

   Comments:

2. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

☐ Yes
☐ No

Comments:

3. Does the entity have any concerns regarding the 2023-02 Implementation Plan? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

☐ Yes
☐ No

Comments:

4. Provide any additional comments for the Drafting Team to consider, if desired.

Comments:

Violation Risk Factor and Violation Severity Level Justifications

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

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 Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues. 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 Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric 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 Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric 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 Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric 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 Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric 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 Electric System, or the ability to effectively monitor and control the Bulk Electric 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 Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric 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-030-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because not having a process for identifying changes in active power output, which is required in defining the minimum standards will be performed, could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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 medium 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-030-1, Requirement R1	
Proposed VRF	**Medium**
than One Obligation	

VSLs for PRC-030-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity failed to implement a documented process to identify changes in active power output in accordance with Requirement R1.

VSL Justifications for PRC-030-1, 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.
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-030-1, Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because a Generator Owner not analyzing it's Inverter Based Resource's performance which are required in defining the minimum standards will be within 90 days of an event, identified pursuant to Requirement R1 or receipt of a request pursuant to Requirement R2, to address the unexpected change(s) in power output and the applicability to its other IBR facilities that could be affected by the same cause of unexpected change(s) in power output could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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	This VRF is in line with the definition of a medium VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-030-1, Requirement R2	
Proposed VRF	**Medium**
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-030-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed an analysis in accordance with Requirement R2, but in more than 90 calendar days but less than 120 calendar days of first identifying an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 120 or more calendar days but less than 150 calendar days of first identifying an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 150 or more calendar days but less than 180 calendar days of first identifying an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 or Part 2.1.4. OR The responsible entity failed to provide the analysis results from the requesting entity in accordance with Requirement R2, Part 2.2.	The responsible entity developed an analysis in accordance with Requirement R2, but in 180 calendar days or more of first identifying an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 and Part 2.1.4. OR The responsible entity failed to document the facility's ride-through performance in accordance with Requirement R2, Part 2.1.2

			OR The responsible entity failed to determine the susceptibility of other inverter-based resource facilities in accordance with Requirement R2, Part 2.1.3.

VSL Justifications for PRC-030-1, 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 Ambiguous Language	The proposed VSLs are not 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-030-1, Requirement R2	
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-030-1, Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because a Generator Owner's failure to develop either a Corrective Action Plan (CAP), or technical justification that addresses why corrective actions will not be applied nor implemented for it's Inverter Based Resource's could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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	This VRF is in line with the definition of a medium VRF requirement per the criteria filed with FERC as part of the

VRF Justifications for PRC-030-1, Requirement R3	
Proposed VRF	**Medium**
Guideline 4- Consistency with NERC Definitions of VRFs	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-030-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 60 days, but provided it within 90 days.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 90 days, but provided it within 120 days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 120 days, but provided it within 150 days OR The developed CAP did not include corrective actions for other facilities owned by the Generator Owners as identified in Requirement R2 Part 2.1.3, if necessary. OR The developed CAP or technical justification was not provided to	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented, within 150 calendar days.

		the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator.	

VSL Justifications for PRC-030-1, 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 not 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-030-1, Requirement R3	
Number of Violations	

VRF Justifications for PRC-030-1, Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because failure to implement, update, or notify with the applicable Reliability Coordinator (RC) the Corrective Action Plan (CAP) for it's Inverter Based Resource's could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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 medium 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-030-1, Requirement R4	
Proposed VRF	**Medium**
than One Obligation	

VSLs for PRC-030-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R4.

VSL Justifications for PRC-030-1, 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 not 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-030-1, Requirement R4	
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.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

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

Formal Comment Period Open through July 10, 2024

Now Available

A 34-day formal comment period for draft two of **PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation**, is open through **8 p.m. Eastern, Wednesday, July 10, 2024**.

The standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

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.

- *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 a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **July 1-10, 2024**.

For 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 470-755-0346. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues 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:	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues | Draft 2
Comment Period Start Date:	6/7/2024
Comment Period End Date:	7/10/2024
Associated Ballots:	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Implementation Plan AB 2 OT 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues PRC-030-1 AB 2 ST

There were 49 sets of responses, including comments from approximately 152 different people from approximately 101 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Does the entity believe there should be any proposed changes in the thresholds in Requirement R1?

2. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

3. Does the entity have any concerns regarding the 2023-02 Implementation Plan? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

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
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,SPP RE,WECC	SRC 2024	Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	1	WECC
					Helen Lainis	IESO	1	NPCC
					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
Exelon	Daniel Gacek	1		Exelon	Daniel Gacek	Exelon	1	RF
					Kinte Whitehead	Exelon	3	RF
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	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern	1	SERC

Company Services, Inc.						Company Services, Inc.		
					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
					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
					Nicolas Turcotte	Hydro-Quebec (HQ)	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	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 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 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	6	SERC

						Cooperative, Inc.		
					Chuck Booth	Associated Electric Cooperative, Inc.	5	SERC
					Jarrod Murdaugh	Sho-Me Power Electric Cooperative	3	SERC

1. Does the entity believe there should be any proposed changes in the thresholds in Requirement R1?

Kim Thomas – Duke Energy	
Answer	No
Document Name	(if an attachment is provided by submitter)
Comment	
None	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
(Drafting team's response to submitter's comments)	

Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	No
Document Name	
Comment	
SMEs responded with the following: "If this standard is enacted the threshold should be high to trigger events. There are too many variables to reliably screen out excluded events so a significant amount of time will be required just to determine if events should be analyzed.	
Likes 0	
Dislikes 0	
Response	

Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	No
Document Name	
Comment	
If this standard is enacted the threshold should be high to trigger events. There are too many variables to reliably screen out excluded events so a significant amount of time will be required just to determine if events should be analyzed.	
Likes 0	

Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy has no issue with the proposed changes to the threshold in Requirement R1.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Patricia Ireland - DTE Energy - 4	
Answer	No
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	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2024	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	

In reading the Technical Document in context with the question there seems to be some inconsistency. The Technical Document uses the terms “sudden changes in active power” and “unexpected”, however R1 has been edited to state “changes in active power output”. This can be interpreted to refer to “any changes inactive power output”. This is overly broad and can be misapplied. Further, the requirement refers to “Examples including changes in wind, solar irradiance”.

If R1 is deemed a valid requirement then the process should focus on early detection and notification/communication. Documented processes for equipment failures or predicted longer term weather events seems more practicable. Most importantly unexpected, unwarranted or unreliability performance should require a process to analyze the root cause and correct deficiencies.

The Drafting Team should focus on the stated purpose of the SAR:

“The scope of this project is to either create a new NERC reliability standard or modify an existing standard that requires IBRs that respond to grid disturbances in an unexpected, unwarranted, and unreliable manner to identify, analyze, and mitigate performance issues that occur within the facility. This includes any types of protections or controls that result in abnormal performance issues within the plant, including abnormal performance resulting in anomalous behavior of active power output from the facility during events.”

The wording of R1 does not support this statement of the scope of the project from the SAR. The Drafting Team should be more assertive in requiring GOs with IBRs to perform to a defined set of criteria to remain compliant. This includes full event analysis and root cause investigations where they violate performance criteria. Criteria can be softened so they do not have to perform perfectly 100% of the time, but there should be a threshold for performance.

Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Dominion Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

AEP supports the SDT's recommended threshold values in Requirement R1, however it is not explicitly stated in R1 where the measurement needs to be taken. AEP suggests adding the text "individually, at each MPT level" or some other defined point.	
Likes 0	
Dislikes 0	
Response	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Our concern here is if there is a fault on the system there will be a momentary reduction in power output and it takes time (~ less than 500ms) for the output to return to steady state. Our main problem with the standard is all the burden is on the IBR GO, GOs would be required to evaluate "any" power loss event that is not excluded which is unnecessary in my opinion . Unless a facility fails to ride through a system disturbance then failures or issues at an individual site will probably not have much of an impact on the BES. Failures during ride through events should be evaluated.	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
The requirement mandates "a documented process to identify changes in active power output that are the greater of 10% of the plant's gross nameplate rating or 20 MW." The BES definition's lower limit is 20 MVA. Therefore, assuming 100% PF, a unit at this lower limit would basically have to be totally lost in order for this requirement to come into play. On the flipside, take a 1,000 MVA plant - again, assuming 100% PF, it would have to lose (or gain) 100 MW for the requirement to be applicable. Is this the SDT's intent? If so, that's a pretty wide difference. If not, seems like the requirement's wording should be lower rather than greater.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	

Answer	Yes
Document Name	
Comment	

Constellation supports NAGF comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5

Answer	Yes
Document Name	
Comment	

Constellation supports NAGF comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6

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:

Comments: EEI appreciates the DT's efforts to set reasonable and workable thresholds for IBR GOs, however, we are concerned that photovoltaic (PV) plants could potentially be over burdensome administratively given the identified threshold for Real Power output changes of 10% of the plant's nameplate (or 20MW) over a 4 second period. While we understand why the DT chose the 4 second time period, we have no data to validate this is sufficiently narrow to avoid confusing changes in solar irradiance with a plants response to a system disturbance. We further note that for very large PV Plants, this threshold is likely sufficient, but we are concerned that smaller plants could be negatively impacted. To address this concern, we ask that

the DT, NERC or one of the technical committees develop an investigation and written technical justification to support the proposed threshold and or consider consulting with NREL or EPRI to validate the veracity of the proposed threshold.	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
R1. A 10% change in the active power output is too low and not the right metric. There are likely to be 10% changes that are not attributed to system disturbances which impact the plant operation, especially for wind or solar. The value should be raised back up to a 20% change. The cost of analyzing every 10% change is not commensurate with the benefit and does not focus on the intent of the SAR. The Standard should focus on the loss of individual generating units not on balance of plant protection systems.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Avista agrees with the EEI Near Final Draft comments and concerns discussed in the draft comments.	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	

TEPC agrees with EEI's comments asking for a technical justification to support the proposed threshold.

Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Tri-State supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
AES CE believes that the extension of the 2 second duration in R1 to 4 seconds will introduce a significant amount of new events requiring analysis and does not align with the Technical Rationale language that “The intent is to exclude from review slow power changes expected with normal operations”.	
Likes 0	
Dislikes 0	
Response	
Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
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.

We support the goals of this standard to analyze and mitigate IBR performance issues; however, the standard as written would require significant analysis of events where IBR facilities respond to grid events *correctly*. This would not be cost effective and not aligned with the intention of the SAR as written. The major driver for this is the trigger criteria defined in Requirement R1. Requirement R1 defines the changes in active power output “occurring within a four-second period.” The “within four-second period” characterization may miss controller oscillations, control interactions, and slower active or reactive power responses in the wrong direction than intended. It would also pick up all types of dynamic events of an IBR facility, including events where an IBR facility performs correctly. This would lead to detailed forensic event analysis for almost every type of grid event rather than only those events where abnormal performance occurred.

Providing guidance in Requirement R1 for the trigger of the events of concern is a good practice but limiting the requirement language to specify only one trigger (e.g., the “changes in active power output occurring during a period that is no longer than 4 seconds”) to capture any type of unexpected changes with an IBR could result in certain types of events being missed while also capturing many events that don’t need to be analyzed (e.g., correct/intended responses of an IBR). The recommendation would be to include a set of event triggers as sub-requirements under Requirement R1.

Example triggers could include:

(1) ***Unexpected*** changes in active or reactive power output within a four-second period

(2) ***Unexpected*** changes in active or reactive power output ***longer*** than a four-second period, including momentary cessation, partial or full IBR tripping, or detailed recovery of active power response post-fault

(3) Active or reactive power oscillations that are poorly damped or persist for longer than *[consider value]* seconds

This structure would give the opportunity for additional triggers to be easily added and implemented/considered to more suitably capture unexpected operations occurring from IBRs on the BPS.

If additional trigger criteria are not used, another approach would be to modify the existing “within four-second window” criteria by adding additional SCADA scan rate samples into the existing trigger. Specifically, this would ensure that correctly performing dynamic events would ***not*** be considered within scope, and rather only significant power output changes that are sustained (i.e., trip of an IBR, active power output jump up/down that remains longer than a dynamic event such as momentary cessation or delayed power recovery, etc.). This would align with the language in the SAR to identify IBRs that incorrectly perform during dynamic grid events by either tripping, reducing active power, and not returning to pre-event output levels within 1-second.

Example criteria language for Requirement R1 along these lines could be:

“Changes in active power output that are the greater of either 10% of the plant's gross nameplate rating, or 20 MW, and the change in active power output remains at the new value for two or more consecutive SCADA scan rates [or could say remains at the new value for 2 seconds or longer].”

In addition, the drafting team should consider modifying Requirement R1 and Requirement R2 so that changes in power output are not limited to just active power, but also reactive power. In fact, Requirement 2.1.2 highlights documentation a facility’s ride-through performance including reactive power responses during grid events.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	Yes
Document Name	

Comment

Yes, Black Hills Corporation feels changes are needed for Requirement 1. We are concerned for small photovoltaic (PV) plant could potentially be overburdened administratively given the identified threshold for Real Power output changes of 10% of the plant's nameplate (or 20 MW) over a 4 second period. We further note for very large PV plants, this threshold is likely sufficient. Black Hills Corporation requests clarification as to the basis/justification for the 4 second event threshold. Request the SDT Team to consider increasing the 4 second event threshold to capture only those Inverter-Based Resource (IBR) events that have a meaningful impact on the BPS.

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

SMUD supports the comments submitted by AES Corporation.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	Yes
Document Name	

Comment

The NAGF requests clarification as to the basis/justification for the 4 second event threshold identified in Requirement R1. The NAGF requests the Drafting Team to consider increasing the 4 second event threshold to capture only those Inverter-Based Resource (IBR) events that have a meaningful impact on the BPS. In addition, the NAGF notes that the event identification and post-event performance validation process will largely be a manual labor-intensive process. Setting the right thresholds to only identify IBR events that have a meaningful impact to the BPS will help ensure optimal use of GO staff resources when identifying/analyzing such events.

Likes 2	JEA, 1, McClung Joseph; Scott Brame, N/A, Brame Scott

Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
We agree with the EEI's comments and concerns discussed in their comments.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Avista agrees with the EEI Near Final Draft comments and concerns discussed in the draft 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), North American Generator Forum (NAGF), and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 1	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
WECC believes the second draft is better developed but the risk is not being effectively mitigated. Leaning heavily on a GO analysis to develop a CAP OR provide a technical justification. And one of the "technical" justifications provided indicated the IBR was connected under old interconnection requirements (effectively grandfathering in everyone!). Also very concerned about the Implementation Plan that hinges on PRC-028 and PRC-029--Really need a complete diagram of the expectations of all 3 Standards (and the others associated with the Projects). PRC-028 is basically not completely effective until 2030. There is not a defined term that matches “Transmission Provider”. Did the DT mean “Transmission Service Provider (TSP)”? As such, a TSP may not own any interconnection (e.g., ERCOT is the only TSP in the Texas Interconnection and has no interconnection facilities.) This needs to change to Transmission Owner(s) to be clear. WECC appreciates the DT’s approach to implementing a “documented” process. There are some discussions	

being held in the industry that mentioned removal of “documented” for compliance risk concerns. There is a bigger reliability risk without documented procedures to guide mitigation of the risks proposed by this Standard and others. It should be clear that R2 allows the RC, BA, or TOP to identify a Disturbance and a change in the inverter-based resource active OR reactive output and the GO should analyze the issue. This should not limit the RC/BA/TOPs to pursue IBR related events EVEN those not meeting the criteria for a GO to self-identify. Requirement R2.1 uses “IBR” versus “inverter-based resource” (as used in Requirement R2.1.4). It should be clear that if a RC, BA, or TOP provides a “request” trigger for actions a GO shall perform, per the base language in Requirement 2, there is not a need to “request” the output of the analysis in Requirement 2.2. Easily see an entity not retaining evidence to clearly demonstrate provision of the analysis indicating there was not a request for said analysis. Why would a RC, BA, or TOP simply request an analysis if the analysis would not be provided? The Technical Rationale indicates “some events would only be identified by one entity” while the Requirement is clear the GO must have a process to identify and the RC/BA/TOPs is limited in some respects under this Requirement. Suggest dropping “Upon request” at the start of Requirement R2.2. Setting the trigger off the gross nameplate value may mask significant events. The PV example 2 exhibits a 30% drop in Real-time output yet does not qualify. If other PV facilities are experiencing the same output level (75% of gross nameplate) because the time of day and an event occurs that drops 30% of all the inverter-based resources in the area, no self-analysis of the event is required. Consider changing the criteria to Real-time output to fully capture the risks. “Ride-through” should be listed as a term here with references to the Project proposing the definition (understand the Implementation Plan mentions approval of Prerequisite Standards.) There is no clarity in what “susceptibility” means in this context. The previous language regarding applicability should be retained. How will an entity demonstrate its determination of susceptibility? If an entity identifies NO performance issues and no corrective actions based on its analysis, how does that get communicated to the RC/BA/TOP? If the rigor of analysis dictates the path forward in the Standard (i.e. development/Implementation of a CAP) what incentives a GO to provide rigor in the analysis? Does the RC/BA/TOP have any mechanism to require corrective actions after a review of the analysis? Requirement R3 should use numbered bullets for consistency. The first bullet in Requirement R3 correctly addresses other applicable facilities but incorrectly identifies Requirement R2 Part 2.1.3 (Should be Requirement R2 2.1.4). Just to be clear, the developed CAP is to be provided to the applicable RC, BA, AND TOP (all three entities not just one), correct? Technical justifications should be limited to equipment limitations. CAPs could include changes in settings that were not initially recognized as a reliability risk but events have proved otherwise. Should add “(CAPs)” in Requirement R4 first sentence for consistency. Requirement R4 does not set any timeframes for expected completion of a CAP. An open-ended CAP does not appear to support reliability and the risk associated with IBR performance should be mitigated as quickly as possible. Also, notification of changes in the CAP or completion of the CAP is limited to the RC but should include the BA and TOP. Suggest “Notify the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator if CAP actions or timetables change and when the CAP is completed.” Measure R4 would need the addition of BA and TOP as well. Measure M4 needs to reference “Requirement R4” not “Requirement R3” in the last sentence.

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	Yes
Document Name	

Comment

The background information presented in this comment form aligns with the industry need outlined in the SAR.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI appreciates the DT's efforts to set reasonable and workable thresholds for IBR GOs, however, we are concerned that photovoltaic (PV) plants could potentially be over burden administratively given the identified threshold for Real Power output changes of 10% of the plant's nameplate (or 20MW) over a 4 second period. While we understand why the DT chose the 4 second time period, we have no data to validate this is sufficiently narrow to avoid confusing changes in solar irradiance with a plants response to a system disturbance. We further note that for very large PV Plants, this threshold is likely sufficient, but we are concerned that smaller plants could be negatively impacted. To address this concern, we ask that the DT, NERC or one of the technical committees to develop an investigation and written technical justification to support the proposed threshold and or consider consulting with NREL or EPRI to validate the veracity of the proposed threshold.	
Likes 0	
Dislikes 0	
Response	

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) does not support the 4 second reporting requirement in the proposed standard draft as that reporting occurrence wouldn't add value and could add unnecessary reporting constraints.	
Likes 0	
Dislikes 0	
Response	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
The MRO NSRF does not believe that the proposed changes in the thresholds are sufficient. Requirement R1, as proposed, focuses on changes in active power output, less a few scenarios, which was not the intention of the SAR.	

Pursuant to the SAR (emphasis added), § Requested Information, ¶2, “IBRs to ensure that any unexpected ceasing of current injection (partial or full) is analyzed by the applicable Generator Owner and mitigated to the extent possible. NERC has also highlighted that many Generator Owners are not aware of these trips and that the Balancing Authority or Reliability Coordinator may often identify the unexpected or unwarranted tripping issues.”

From the excerpt above it is clear that the proposed standard should focus on trips not caused by balance of plant (BOP) Protection Systems, but trips of the individual generating units. As such, the proposed Requirement R1 language needs to focus on generation resource capability, which is based on availability of individual generating units multiplied by the of individual generating unit’s nameplate. For example, consider a wind generation resource with a 100MW aggregate gross nameplate that consists of 50 2MW individual generating units. When the wind generation resource is at 100% availability, then its capability would be 100MW, regardless of fuel supply. If the wind generation resource had 25 individual generating units trip in a short period of time (≤ 1 minute), the new capability of the wind generation resource is now 50MW. The intention of the SAR was for Generator Owners to analyze these types of events (individual generating unit trips) to determine if performance issues exist, not any change in active power output.

It is not reasonable or practicable to have Generator Owners analyze every change in active power output even with the exclusions outlined in the proposed requirement. The MRO NSRF strongly encourages the SDT to consider the process that will be required to demonstrate compliance with the proposed Requirement R1 and the amount of administration that will be required to verify whether or not a change in active power meets the criteria for analysis in the Proposed Requirement R1.

The MRO NSRF believe that the that 10% change in the active power output is too low – there are likely to be 10% changes that are not attributed to system disturbances which impact the facility operation. It is suggested that this value be raised back up to 20% range of change.

An MRO NSRF member performed an analysis on one of their IBR facilities (100MW w/ 34 wind turbines) to determine the amount 10% or 20% changes in active power that occur from four-second to four-second or 60 second to 60 second time periods over a six-hour period, the results are as follows.

10% active power change

Total 4s Periods in a 6hr Period = 5400

Total PRC-030 Analysis’s Required for a 6hr Period = 2250 or 41.667% (No Requirement R1 exclusions considered)

Please note that there were no 10% capability changes over this six-hour time period.

20% active power change

Total 60s Periods in a 6hr Period = 360

Total PRC-030 Analysis’s Required for a 6hr Period = 150 or 41.667% (No Requirement R1 exclusions considered)

Please note that there were no 20% capability changes over this six-hour time period.

An additional concern the MRO NSRF has with the four second time frame is that BAL-005-1 R1 specifies a design scan rate of no more than six seconds for acquiring data necessary for calculating ACE and sending to the BA. That is really the defining time frame that is used to setup EMS systems to query BES RTU data. In addition, other entities could have longer scan rates up to 6 seconds. This is also dependent on the communications path and bandwidth available from EMS to the RTU. If a channel has multiple RTU connections on it, then the scan time can vary as it has to be tuned to be able to respond successfully given the bandwidth available to the multiple RTUs on the channel. The MRO NSRF believes that four seconds may be unachievable for some entities and it seems like the four second time should consider BAL-005-1 and an the amount active power changes that occur at an IBR. The MRO NSRF does not believe that amount of precision can actually be achieved the way EMS systems are communicating with BA/RCs today unless some other monitoring mechanism is used.

As such, the MRO NSRF suggest using a 20% change in capability over a one-minute time period to be the threshold for Requirement R1.

Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	

As previously commented, WEC Energy Group does not agree with the 10% or 20 MVA threshold. The technical rationale states that “was chosen to be large enough to screen out normal operational events but not so large that it does not detect events that should be analyzed”. We do not agree that it is large enough to screen out normal events. The “unexpected changes” attributed to weather patterns, change of wind and/or change in irradiance factors occur on a daily basis in some geographical regions, often multiple times per day and can easily drop the site output by 10% or 20MVA. Therefore WEC Energy Group proposes that the threshold should be set to at least 75% of the site nameplate.

WEC Energy Group agrees with the MRO NSRF comments/suggestion to merge R1 and R2.

Likes 0	
Dislikes 0	
Response	
Douglas Darrah - Clearway Renewable Operation and Maintenance LLC - 5 - MRO,WECC,Texas RE,RF	
Answer	Yes
Document Name	
Comment	

Clearway Renewable Operation and Maintenance LLC ("Clearway") supports the NAGF's comments requesting clarification as to the technical basis for the 4 second event threshold and emphasizing the need to create a standard that optimizes GO staff resources.

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	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

To align with the SAR, the criteria for R1 should include 1.) Any complete facility trip/loss (regardless of the MW output at the time of the event) OR 2.) The ***lower*** of 10% of the plant's ***gross MW output or input*** or 20 MW if the SDT continues with those thresholds. The 10% threshold may be considered reasonable for the majority of existing IBRs in operation; however future IBRs in the interconnection queue are rapidly growing in size. As of July 1, 2024, 744 new IBR projects in ERCOT will be greater than 200 MW. 85 of those will be greater than 500 MW and 7 of those greater than 1,000 MW. This means that reductions of greater than 100 MW for a 1,000 MW IBR plant could occur that would not be required to be analyzed. If a percentage threshold is still utilized in part of the criteria, it should be replaced with gross active power output (or input for storage). While solar sites may very well be closer to nameplate for several hours each day, wind resources are rarely beyond 60%-70% nameplate in ERCOT. Storage IBRs are even less often at nameplate. While ERCOT understands that the RC/BA/TOP may request disturbance data as well, it would be better to improve the criteria for R1 to minimize the need for such requests, allow greater self-monitoring to improve reliability, and minimize conflicts for such requests.

ERCOT also recommends clarifying the first sentence to clarify that the active output level must equal or exceed the defined threshold value. Thus, the sentence should be revised to reference "changes in active power output **or input that equal or exceed** the **lower** of 10% of the plant's gross **MW output or input** or 20 MW."

It is also unclear why the term “Transmission Provider” is being used. The SDT should review the standards or confer with NERC staff on the best functional entity or descriptor for the interconnection transmission provider. Perhaps “Transmission Owner” is the best term.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	Yes
Document Name	

Comment

Ameren agrees with most of NAGF's comments, but with one difference. We believe the time period threshold in R1 of PRC-030 should align with PRC-029 if possible or provide a technical basis for choosing 4 seconds. For example, the present draft of PRC-029 dated 2024-03-27 shows a voltage ride-through requirement of 10 seconds for non-wind IBR and 1800 seconds for wind IBR which differs from the 4 second time as used in PRC-030. If the two standards are aligned, clarification should be made in PRC-030 or PRC-029 that if it is discovered that the IBR did not ride-through the expected time, it does not result in a violation of PRC-029 if the PRC-029 study was conducted prior to placing the plant in-service.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	Yes
Document Name	

Comment

OPG supports NPCC Regional Standards Committee’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	Yes
Document Name	

Comment

Southern Company believes that the 10% change in the active power output change is too low. Tthere are likely to be 10% changes that are not attributed to system disturbances which impact the plant operation. Southern Company suggests that this value be raised back up to a 15-20% change.

Southern Compay also suggests that footnote 2 be included in the bullet of R1 to eliminate the footnote altogether.

In the first sentence of Requirement R1, Southern Company suggests adding “MVA” before “nameplate rating”. The intent is not to change any requirement but only to clarify how the required trigger point is determined.

Likes 0	
Dislikes 0	

Response

Michael Goggin - Grid Strategies LLC - 5

Answer	Yes
Document Name	

Comment

We are highly concerned that the updated standard reduced the threshold for output change events that must be reviewed to determine if they need to be analyzed. The revised standard sets the threshold at a change in output that is greater than 10% of the plant’s nameplate rating (or 20 MW) within 4 seconds, relative to the previous threshold of 20% within 2 seconds. This change only adds to the generator owner’s burden of manually reviewing each output change to exclude events caused by normal fluctuations in plant output due to weather, dispatch, and other factors. No mechanism exists for generator owners to automatically exclude those permissible changes from consideration. Wind and solar plants have a limited number of meteorological towers and pyranometers for measuring the available wind and solar resource, respectively, which makes it difficult in many cases to precisely determine whether changes in output across a plant were caused by resource availability.

The new lower threshold will pick up many more such events, as changes of 10% output within 4 seconds routinely occur at solar and wind plants. As we explained in our previous comments, the passage of clouds over small to medium solar plants can cause changes in output of 75% of nameplate capacity per second.[1] As a result, in many cases the vast majority of events a generator owner is required to review will be these normal changes in output, diverting their time and resources away from addressing real reliability concerns.

The drafting team’s response to our prior comments only reinforces our concern about the burden imposed on the generator owner: “GOs would not know if it was unexpected behavior of generator settings and controls until the analysis is performed. The exceptions that have been moved from the footnote to the Standard Language allow for GOs to dismiss events due to cloud cover, change in wind speed. etc. Outage/Fault codes would be reviewed during the analysis process. It will be up to GOs to develop a process to identify events that that do not fit into the listed exclusions and require further analysis.” It is highly burdensome for a generator owner to pull turbine- or inverter-level fault codes and plant-level fault codes for each event with a more than 10% change in output. Moreover, the drafting team cannot ignore the excessive and unworkable burden imposed on generator owners by simply dismissing that with “It will be up to GOs to develop a process to identify events that that do not fit into the listed exclusions and require further analysis.”

As explained in our answer to question 2 below, the best solution to these concerns may be to remove most if not all of R1, and instead rely on analysis requests initiated by the Reliability Coordinator, Balancing Authority, or Transmission Operator following a disturbance event that causes a drop in generator output per R2.

{C}[1]{C} https://www.sciencedirect.com/science/article/abs/pii/S0306261917300144

Likes 0	

Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	Yes
Document Name	

Comment

As drafted, the thresholds in Requirement R1 place a large burden on IBR GOs to analyze events where unexpected changes in active power output occur and events where IBRs respond correctly to System events. We believe this goes against the intent of the SAR, which is "to ensure that any **unexpected** ceasing of current injection (partial or full) is analyzed by the applicable Generator Owner and mitigated to the extent possible."

In many cases, irradiance or wind speed data is not captured at such a high resolution from MET stations or it could be limited by data loggers in the field. The thresholds in R1 would result in significant work on the backend to isolate unexpected changes in active power output from changes associated with resource availability or even changes associated with an expected response to a System event. Consider utilizing SCADA scan rates rather than seconds in the threshold criteria.

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5

Answer	Yes
Document Name	

Comment

As drafted, the thresholds in Requirement R1 place a large burden on IBR GOs to analyze events where unexpected changes in active power output occur and events where IBRs respond correctly to System events. We believe this goes against the intent of the SAR, which is "to ensure that any **unexpected** ceasing of current injection (partial or full) is analyzed by the applicable Generator Owner and mitigated to the extent possible."

In many cases, irradiance or wind speed data is not captured at such a high resolution from MET stations or it could be limited by data loggers in the field. The thresholds in R1 would result in significant work on the backend to isolate unexpected changes in active power output from changes associated with resource availability or even changes associated with an expected response to a System event. Consider utilizing SCADA scan rates rather than seconds in the threshold criteria.

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	Yes
Document Name	
Comment	
The percentage of change in active power output identified in R1 should be put back to 20% of the plant's gross nameplate rating as in draft 1 instead of 10%.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE recommends clarifying Requirement R1 to state that the GO shall implement a documented process to identify all changes in active power, not just changes in active power output. The Technical Rationale appears to support this its use of the phrase "changes in active power".

Additionally, Texas RE recommends clarifying Requirement R1 to indicate whether the changes in active power correspond with the duration of the system disturbance. If the intent of the SDT to capture decrease in active power output during any disturbance event regardless of the duration of the disturbance, Texas RE recommends the following revisions. Additionally, Texas RE further asserts that the exemptions in R1 for loss of transmission facilities should apply only to radial facilities and not to locations where multiple transmission lines are terminated at the Point of Interconnection (i.e. loop fed transmission stations or substations). Texas RE's proposed revisions to the language in R1 are provided in bold below:

R1. Each applicable Generator Owner shall implement a documented process to identify changes in active power **output** that are the greater of 10% of the plant's gross nameplate rating or 20 MW, and occurring **within during** a **four second** period **that is no longer than 4 seconds**. Changes in active power for the following are excluded: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

- Changes associated with intermittent primary energy source2 availability;
- Resource dispatch, resource ramping, planned outages, or planned resource testing; or
- Loss of Transmission Provider's **radial** facilities **to the Point of Interconnection**

Likes 0	
Dislikes 0	
Response	
Scott Thompson - PNM Resources - 1,3,5 - WECC	
Answer	
Document Name	

Comment	
Yes, PNM supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	

2. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

Kim Thomas – Duke Energy	
Answer	Y/N
Document Name	(if an attachment is provided by submitter)
Comment	
Duke Energy requires more information to adequately assess alternatives associated with FERC Order 901.	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
(Drafting team's response to submitter's comments)	

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	

Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Until Avista owns BPS IBR's generation, the standard has no effect on Avista. If we own IBR generation, we will need digital fault recorders (DFR's) installed to comply with the recording requirements.	
Likes 0	
Dislikes 0	

Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
Until we own BPS IBR's generation, the standard has no effect on us. If we own IBR generation, we will need digital fault recorders (DFR's) installed to comply with the recording requirements.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
Until Avista owns BPS IBR's generation, the standard has no effect on Avista. If we own IBR generation, we will need digital fault recorders (DFR's) installed to comply with the recording requirements.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy offers no alternatives toward the cost effectiveness of these recommendations.	
Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
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	No
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	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Ireland - DTE Energy - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
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	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	
Invenergy is not in a position to comment on the overall cost-effectiveness of the proposed standard as it relates to BES reliability.	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
Invenergy is not in a position to comment on the overall cost-effectiveness of the proposed standard as it relates to BES reliability.	
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 believes that perhaps determining subsections of the North American electric grid where this detailed monitoring and analysis is most needed rather than requiring it across the entire geographic area is an alternative and more cost-effective option to address the recommendations in the FERC Order. The system stiffness to voltage and frequency fluctuations should be accounted for in regions where the IBR facilities are not likely to be affected by abnormal system condition events. Any possible reduction in the number of facilities required to install this equipment is a direct cost reduction.

Souther Company suggests the SDT remove the documented process and just state the GO shall perform a Root Cause Analysis of the performance deviation as there is no need to do all of the documented process steps. Then require the GO shall have documented evidence it performed an RCA on events that qualify.

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	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	Yes
Document Name	
Comment	

The MRO NSRF does not believe that this is cost-effective as currently proposed. Please see the MRO NSRF’s other responses to questions. Perhaps determining subsections of the North American electric grid where this detailed monitoring and analysis is most needed rather than requiring it across the entire geographic area. The system stiffness to voltage and frequency fluctuations should be accounted for in regions where the IBR facilities are not likely to be affected by abnormal system condition events. Any possible reduction in the number of facilities required to install this equipment is a direct cost reduction.

Likes 1	Lincoln Electric System, 1, Johnson Josh
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 Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 2

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	Yes
Document Name	

Comment

Minnesota Power supports MRO’s NERC Standards Review Forum’s (NSRF) comments.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	Yes
Document Name	

Comment

Tri-State supports the comments submitted by the MRO NSRF.

Likes 0	

Dislikes 0	

Response

Brian Lindsey - Entergy - 1

Answer	Yes
Document Name	

Comment

The Standard should be focused on sections of the grid where these disturbances have caused problems. Throwing every conceivable benefit to planners does not ensure that there will be any improvement in reliability. The BAs and the RCs have their work cut out for them and must be or become knowledgeable enough to identify the needs. The real problem is the loss of spinning inertia. There should be a moratorium on retiring generations until solutions are in place and grid stability is restored.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	Yes
Document Name	

Comment

Constellation supports NAGF comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	Yes
Document Name	

Comment

Constellation supports NAGF comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	Yes
Document Name	
Comment	
This standard is essentially an extension of MOD-033 and PRC-002. Modifications of these standards should be made instead of a new standard created since this is not to analyze trip events but to analyze continuous system behavior.	
Likes 0	
Dislikes 0	
Response	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
SMEs responded with the following “This standard is essentially an extension of MOD-033 and PRC-002. Modifications of these standards should be made instead of a new standard created since this is not to analyze trip events but to analyze continuous system behavior.”	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	

Yes, the Drafting team should identify specific performance criterion and require GOs who own IBR resources to meet that performance level. Event Analysis should be completed consistent with Standards like PRC-002, PRC-003 and PRC-004. The key is that the standards must state what the performance measurement is, and then through reporting and auditing compliance would be clearly objective.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
NV Energy agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 5	
Answer	
Document Name	
Comment	
To address the concerns we expressed in answer to question 1 above regarding the burden on generators of screening out changes in output that are not caused by disturbances, the best solution may be to remove most if not all of R1, and instead rely on analysis requests initiated by the Reliability	

Coordinator, Balancing Authority, or Transmission Operator following a disturbance event per R2. This would remove the inefficient “needle in the haystack” burden on generators under R1 to screen every output change event to find the small subset that are due to disturbances, and instead only focus resources on reviewing disturbance events that coincided with a change in output. Because many generators do not have synchrophasors or other equipment required to determine when grid disturbances have occurred, it makes more sense for the analysis to be initiated by a request from the RC, BA, or TO.

We also reiterate our request from the last comment period to add a requirement to R2 that the RC, BA, or TO must file its request within 15 days of the disturbance event. This will ensure that the GO has at least five days to pull data before it is overwritten, given that the data retention period in the current draft of PRC-028 R7 is 20 days.

Finally, the requirement on the generator owner in 2.1.4 for “Determination of the susceptibility of its other inverter-based resource facilities to similar events” appears to be unreasonable if not unworkable. A company that owns multiple IBR plants typically uses different equipment and settings across its plants, and some may be wind plants while others are solar plants, so there is no reason to assume its other plants have the same susceptibility simply because they have the same owner. At minimum, the requirement should be clarified to specify whether non-BES IBR plants owned by the same owner must be assessed as part of compliance with 2.1.4., whether projects owned by the same parent company but are actually separate LLCs must be assessed as part of compliance with 2.1.4., and other such details.

Likes 0	
Dislikes 0	

Response

Scott Thompson - PNM Resources - 1,3,5 - WECC

Answer	
Document Name	

Comment

By making EEI's suggested changes to R1, that should lessen the administrative cost associated with the standard. By not capturing everyday and common occurances, operational costs required to remain compliant with the standard should decrease.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	
Document Name	

Comment

Ameren agrees with NAGF's comments.

Likes 0	

Dislikes 0	
Response	
Douglas Darrah - Clearway Renewable Operation and Maintenance LLC - 5 - MRO,WECC,Texas RE,RF	
Answer	
Document Name	
Comment	
Clearway will need more information to evaluate the proposed approach.	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI has no suggestions for alternatives in addressing the associated FERC Order 901 directives that are being covered within 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 RSC	
Answer	
Document Name	
Comment	

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."

It is imperative that the standard drafting teams for this project as well as the 2021-04 (PRC-002 and PRC-028) and 2020-02 (PRC-029 and PRC-024) assure a coherent way of addressing the inclusion and exclusion of IBRs in current and upcoming standards. These three different projects have all used different ways of drafting up section 4.2 of the standard.

The following comments are specific to PRC-030-1, Requirement R1:

- Add an exclusion for active power changes linked to frequency regulation and power limitations/runback ordered by the TO.
- Add an exclusion for faults inside the IBR plant.

Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	

No comment on cost-effectiveness. WECC leaves that to the applicable entities.

Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	

Answer	
Document Name	
Comment	
GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.	
Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost-effectiveness.	
Likes 0	
Dislikes 0	
Response	

3. Does the entity have any concerns regarding the 2023-02 Implementation Plan? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

Kim Thomas – Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy suggests extending Implementation Plan timeline to 18 months due to budgeting, planning, procurement, installation/implementation, and vendor concerns.	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
(Drafting team's response to submitter's comments)	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	
Comment	
FirstEnergy has no objections to the proposed Implementation Plan.	
Likes 0	
Dislikes 0	
Response	

Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
Not applicable to Avista at this time	
Likes 0	
Dislikes 0	

Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO’s NERC Standards Review Forum’s (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
Not applicable to us at this time since we do not own any IBR generation.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Not applicable to Avista at this time	
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 Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI has no objections to the proposed Implementation Plan.	
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 have any concerns with the Implementation Plan with acknowledgment of changes needed as noted in the previous questions and in the Additional Comments below.	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	No
Document Name	
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	

Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
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	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - PNM Resources - 1,3,5 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2024	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
For many entities the Standard, as proposed, will require more than 6 months to implement and be compliant with. Entities should be given 6 months to create a plan and submit it to the Regional Entity for approval. The plan would include when the entity the anticipated date when all facilities can be brought up to compliance.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Implementing changes to the active power output will require software and possibly hardware modifications or additions. Having only six months to design and implement this modification is not reasonable. Instead, AEP recommends an implementation period of 18 months.	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes

Document Name	
Comment	

Having the “process” mandated by Requirement R1 within 6 months is probably reasonable. However, having the “ability” to implement the process within 6 months, if it doesn’t already exist with the plant, will be nearly impossible. It could require a design change, equipment procurement, and plant modification, which could easily take a year or longer, given current manpower and supply chain issues. Additionally, most utilities would likely have to secure the services of a limited number of contracting companies with the necessary experience to do the work.

Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6

Answer	Yes
Document Name	
Comment	

Constellation supports NAGF comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5

Answer	Yes
Document Name	
Comment	

Constellation supports NAGF comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	

The implementation plan should be 365 days instead of 90 days to allow for any control changes that might be required. A process may need to be added to allow extensions of implementation based on potential supply chain issues.

Likes 0	
Dislikes 0	
Response	

Patricia Ireland - DTE Energy - 4	
Answer	Yes
Document Name	
Comment	

The prerequisite section states:

"These standard(s) or definitions must be ***approved*** before the Applicable Standard becomes effective:

- PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
- PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Generating Resources Applicable Entities"

Should be changed to:

"These standard(s) or definitions must be ***implemented*** before the Applicable Standard becomes effective:

- PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
- PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Generating Resources Applicable Entitie"

"These standard(s) or definitions must be ***approved*** before the Applicable Standard becomes effective:

PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Generating Resources Applicable Entitie"

Likes 0	
Dislikes 0	

Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
AES CE agrees with NAGF’s suggestion to extend the proposed Implementation Plan timeline from 6 months to 12 months. This additional time will allow us to explore/configure automation for IBR event identification, event analysis process development/optimization, and corrective action plan development.	
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 requests the proposed Implementation Plan timeline be changed from 6 months to 12-24 months. This will help generator owner/operators to explore & if purchase - configure automation for IBR event identification, plus event analysis process development and corrective action plans.	
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	
SMUD agrees with the NAGF’s suggestion to extend the proposed Implementation Plan timeline from 6 months to 12 months.	

Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF requests the DT to consider extending the proposed Implementation Plan timeline from 6 months to 12 months. This additional time will allow GOs to explore/configure automation for IBR event identification, event analysis process development/optimization, and corrective action plan development.	
Likes 2	JEA, 1, McClung Joseph; Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
There is not clarity in the Implementation Plan as it hinges on the Approval of PRC-028 and PRC-029. PRC-028 has a proposed phased in Implementation Plan extending to 2030. While the PRC-028 Standard itself becomes “effective” the Requirements within the Standard are not applicable at the same time which could affect the applicability of inverter-based resources in PRC-029 and PRC-030. WECC suggests the DTs of each Project (PRC-028/029/030) draw a timeline regarding implementation dates so the industry is clear on the expectations. Leaving it to interpretation without clarity in expectations is a detriment for reliability. PRC-030 makes no distinction between existing inverter-based resources and future inverter-based resources but PRC-028 does. Without clarity provided by the DTs, the implementation of these Standards to mitigate the identified risks will not be successful for entities (both from a reliability and compliance perspective.)	
Likes 0	
Dislikes 0	
Response	
Douglas Darrah - Clearway Renewable Operation and Maintenance LLC - 5 - MRO,WECC,Texas RE,RF	
Answer	Yes

Document Name	
Comment	
Clearway support the NAGF's proposal to extend the Implementation Plan timeline from 6 months to 12 months. As the Generator Owner for over 40 NERC-registered IBRs, Clearway is concerned that the proposed six-month implementation timeline will not give GOs enough time to comply with the proposed standards. Developing the automated monitoring mandated by R1 along with the analysis and reporting procedures required by R2, R3, and R4 will require substantial work to be completed by Clearway's SCADA and engineering teams. A 12-month timeline will meaningfully lessen the compliance burden created by the proposed standard.	
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	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
The Prerequisite section should state that the standards must be approved before "or concurrently with" PRC 028 and 029 to allow for a scenario in which a package of all the standards is submitted to FERC concurrently.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	

Answer	Yes
Document Name	
Comment	
Ameren agrees with NAGF's comments.	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
Considering the amount of data that will need to be filtered, we propose the Implementation Plan be amended to allow entities at least 12 months to implement their process(es) to identify and analyze qualifying events. Alternatively, consider linking the Implementation Plan for PRC-030-1 to that of PRC-028-1, given that the required monitoring equipment may be useful in the identification and analysis of qualifying events.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	
Considering the amount of data that will need to be filtered, we propose the Implementation Plan be amended to allow entities at least 12 months to implement their process(es) to identify and analyze qualifying events. Alternatively, consider linking the Implementation Plan for PRC-030-1 to that of PRC-028-1, given that the required monitoring equipment may be useful in the identification and analysis of qualifying events.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	

Answer	Yes
Document Name	
Comment	
The implementation period should be increased to 2 years to allow for any equipment changes or upgrades needed to comply with the standard.	
Likes 0	
Dislikes 0	
Response	

4. Provide any additional comments for the Drafting Team to consider, if desired.

Kim Thomas – Duke Energy	
Answer	
Document Name	
Comment	

Duke Energy agrees with and recommends implementing the following summarized EEI comments - see EEI submittal for a detailed description of each comment:

EEI COMMENTS
General Comment:
Do not agree with the use of non-glossary terms where glossary terms are available and the use of glossary terms that are not capitalized – see EEI submittal for detailed descriptions and potential resolution(s).

Applicability Section Comments:
Do not agree with the non-industry approved use of Footnote 1 to expand the definition of IBRs and the lack of a technical or SAR justification for the addition of VSC-HVDCs – see EEI submittal for detailed descriptions and potential resolution(s).

Requirements Comments:

Requirements R2 & R3:
Do not agree with the inclusion of requirements that are not clearly defined or sent from multiple registered entities (i.e., RC, BA or TOP) which creates regulatory confusion and undue burden, fails to define compliance responsibility, for functional entity responsibilities not listed in the Applicability section of the Standard – see EEI submittal for detailed descriptions and potential resolution(s).

Requirement R4, Subpart 4.3:
Suggest adding “Upon Request” to Subpart 4.3 for consistency with Requirement R2, Subpart 2.2 because there should not be a regulatory requirement to notify the RC regarding CAP actions, timetables change and when the CAP is completed, unless the RC specifically requests that the GO provide such notification – see EEI submittal for detailed descriptions and potential resolution(s).

Additionally, Duke Energy agrees with and recommends implementing the following summarized NAGF comments - see NAGF submittal for a detailed description of each comment:

NAGF COMMENTS
Provide a technical explanation why in Requirement R2 Part 2.1.3, each applicable Generator Owner shall, within 60 calendar days, provide a CAP or Technical Justification to the RC, BA, and TOP
Finally, Duke Energy submits the following comment for consideration:

DUKE ENERGY COMMENTS

Standard language consideration should be given to GOs reporting/corresponding to the TP instead of the RC for vertically integrated electric utilities.

Consider substituting the following language for R1 to enhance its clarity: "…identify changes in real power output that are at least 20 MW and greater than 10% of the plant's gross nameplate rating,” and occurring during a period that is “within 4 seconds."

Revise Reliability Standard PRC-030-1 June 2024 Technical Rationale Document Figure 1.2: PRC-030-1 Flowchart to read 20 “MW” instead of 20 MVA. Recommend modifying R1 language to read “…occurring during a period that is “within” 4 seconds." to clarify statement.

Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
(Drafting team’s response to submitter’s comments)	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	
Document Name	
Comment	

The time periods in R2 and R3 should be increased to 120 calendar days to allow time to determine the root cause and develop a Corrective Action Plan, especially if OEM support is required.

Likes 0	
Dislikes 0	
Response	

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2024

Answer	
Document Name	
Comment	

Regarding R2, Generator Owners should report performance issues more promptly than 90 calendar days. That report only needs to detail the impact of the performance issue then the 90 day assessment would have details and the Generator Owner can complete analysis and develop a corrective action plan in 90 days. Revise R2 wording to:

R2. Each applicable Generator Owner, within 3 business days , shall report the impact of those performance issues to the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator and within 90 calendar days of identifying an active power change event pursuant to Requirement R1 or following a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the inverter-based resource(s) active power output, shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determination of the root cause(s) of change(s) in active power output;

2.1.2. Documentation of the facility's Ride-through performance including reactive power response during the event;

2.1.3. Assessment of any performance issues identified and if corrective actions are needed; and

2.1.4. Determination of the susceptibility of its other inverter-based resource facilities to similar events.

2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator

R2. If performance issues and corrective actions were identified in Requirement R2 Part

2.1.3, each applicable Generator Owner shall, within 3 business days, report those performance issues to the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator and within 60 calendar days of completing the analysis in Requirement R2, develop one of the following and provide it to the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator. Reports do not have to include details for specific causes but shall provide detail regarding overall impact to the generator facility.

NOTE: MISO is a party to these comments however has opted out of supporting the response to Question 4.

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5

Answer	
Document Name	

Comment

Invenergy thanks the drafting team for the opportunity to provide comments.

Footnote 1: This does not align with the recently approved definition of Inverter-based Resource. If the drafting team intends to include other types of facilities not included in the IBR definition, then those facilities should be separately listed in the Applicability section, rather than as a footnote of BES IBR.

R4.3: This should be removed or amended such that it is only upon request of the Reliability Coordinator.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	
Comment	

NV Energy agrees with EEI comments.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	
Document Name	
Comment	

Invenergy thanks the drafting team for the opportunity to provide comments.

Footnote 1: This does not align with the recently approved definition of Inverter-based Resource. If the drafting team intends to include other types of facilities not included in the IBR definition, then those facilities should be separately listed in the Applicability section, rather than as a footnote of BES IBR.

R4.3: This should be removed or amended such that it is only upon request of the Reliability Coordinator.

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 offers the following comments and questions for the SDT:

- Not seeing relationship of footnote 1 with Facilities 4.2.1.
- Recommend R1 state "… 4 continuous seconds…"
- In R1, delete the word "documented"
- In M1, change"(1) the documented process..." to "(1) implementation of a process for...".
- With the two changes above deleting "documented", item (2) in M1 can be deleted.
- In R2.1.1, be more direct by changing "Determination of the root cause(s)..." to "Determine the root cause(s)..".

- In R2.1.2, be more direct by changing “Documentation of the facility’s...” to “Document the facility’s...”.
- R 2.1.2 remove “…including reactive power response during the event.” as it does not align with the purpose statement or R1. This is the only place Reactive Power shows up.
- In R2.1.3, be more direct by changing “Assessment of any performance...” to “Assess any performance ...”
- In R2.1.3, change the word “needed” to “indicated” to take into account the possibility of there being no changes available to affect the response of the IBR controls to the system disturbance.
- R2.1.4 should be removed. Although a good suggestion, in reality this would be difficult to prove and does not show up in the M2. GOs would naturally want to eliminate issues found if they thought they we systemic across multiple locations.
- Modify M2 to account for the possible request for results of the analysis by the RC, BA, or TOP by changing “Each applicable Generator Owner shall have dated documentation of the required analysis developed in accordance with...” to “Each applicable Generator Owner shall have dated documentation of the required analysis developed, and the delivery of the analysis when requested, in accordance with...”.
- R3 first bullet needs to remove this part of the sentence “…including other applicable facilities owned by the Generator Owner as identified in Requirement R2 Part 2.1.3…”
- R3 second bullet needs to remove the word “technical”. There are other reasons that a CAP would not be implemented, such as cost, plant near end of functional life, etc.
- Does the BA and TOP also need to appear in the new R4.3 since they appear in the new R3/M3?
- Was there a specific reason that the Transmission Planner and/or the Planning Coordinator was not also included in the RC/BA/TOP group each time they appear in the standard? It seems like the Planner may also be interested in the actual performance of the IBR facility.
- Purpose needs to read “Identify, analyze, and mitigate unexpected inverter-based resource (IBR) change of Real Power output. Real Power is a NERC glossary term.
- Change term “active power” to “Real Power” throughout.
- “reactive power”, if used, needs to be capitalized to “Reactive Power” throughout. (Glossary of Terms Used in NERC Reliability Standards)

Likes 0	
Dislikes 0	

Response

John Pearson - ISO New England, Inc. - 2

Answer	
Document Name	

Comment

Under R2, when it is necessary to analyze an event, the GO should notify the applicable Reliability Coordinator, Balancing Authority, or Transmission Operator much more timely than 90 calendar days and a notification should be made the next business day after the event occurred. The notification does not need to include any causal analysis but should provide performance details. The GOs analysis required per R2.1 can be performed within 90 calendar days as described but the RC/BA/TOP should be aware of the potential for such events in the meantime.

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	
Scott Thompson - PNM Resources - 1,3,5 - WECC	
Answer	
Document Name	
Comment	
PNM supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren agrees with NAGF's comments.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

Regarding R2, Generator Owners should be required to promptly notify the RC/BA/TOP of performance issues before conducting the assessment that is contemplated in this requirement to be completed within 90 days. This would allow the RC/BA/TOP to then initiate its review process and request operational data before any retention periods have expired. The initial notification only needs to provide minimum levels of detail (e.g. date/time, unit, MW impact, any initial assessment). . The wording of R2 can be revised or a separate requirement could be created.

RX. Each applicable Generator Owner, shall, before the end of the next business day of identifying an active power change event, notify the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator of the event. The notification shall include at a minimum: date, time, unit, change amount, and any initial known causes.

Also, ERCOT recommends modifying R2 to say the following:

R2. Each applicable Generator Owner, within 90 calendar days of identifying an active power change event pursuant to Requirement R1 or receiving a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a change in the inverter-based resource(s) active power output during or immediately after a Disturbance, shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determination of the root cause(s) of change(s) in active power output;

2.1.2. Documentation of the facility's Ride-through performance including reactive power response during the event;

2.1.3. Assessment of any performance issues identified and if corrective actions are needed; and

2.1.4. Determination of the susceptibility of its other inverter-based resource facilities to similar events.

2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator

R3

For R3, the standard does not provide sufficient clarity about what sorts of technical justifications would justify not implementing corrective actions. For example, would cost be a sufficient ground? As written, the provision for a GO to not be required to implement corrective actions is too broad with no consideration to the reliability impact of not correcting. FERC has recently rejected similarly broad language in the context of NERC-proposed generator weatherization standards. *See* Order Approving Extreme Weather Reliability Standard EOP-012-2 and Directing Modification at p.41, FERC Docket No. RD24-5-000, 21-5-000 (June 27, 2024). Here, as in that case. leaving it up to the generator owner to interpret what it meant to have a technical constraint is unacceptable. The criteria should be "objective, unambiguous, and auditable". *Id.* Moreover, the commission directed in that order that such communications should be confirmed by a reliability entity (e.g. NERC/REs). The need for NERC or RE review should be considered by NERC and the SDT in light of this order, just as the NERC Project 2020-02 SDT is doing for PRC-029.

It is also unclear whether there is any difference between corrective actions "not being applied" and such actions not being "implemented." The current phrasing seems at best redundant.

ERCOT also believes that CAPs that materially modify the generator's response characteristics from those based on existing models should be evaluated by the RC/BA/TOP prior to the GO making such changes, and that models should be updated consistent with NERC recommendations in the

2022 Odessa event report. ERCOT does not believe the obligation to update models is adequately captured in the current MOD standards and recommends this be included in a sub requirement to R4 as follows: "Update any dynamic models to reflect the corrective actions if necessary".

ERCOT also recommends that the Corrective Action Plan should require corrective actions to be implemented within a reasonable timeframe to guard against egregiously long implementation periods.

Finally, ERCOT recommends that the first sentence be clarified to more accurately align with R2's requirement that the GO must identify only a **need** for a CAP within 90 days. So the opening sentence should read: "If performance issues and **a need for** corrective actions were identified in Requirement R2 Part 2.1.3, ..."

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

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	
Document Name	

Comment

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.

Likes 0	

Dislikes 0	
Response	
Douglas Darrah - Clearway Renewable Operation and Maintenance LLC - 5 - MRO,WECC,Texas RE,RF	
Answer	
Document Name	
Comment	
Clearway supports the additional comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
WEC Energy Group agrees with the MRO NSRF about adding exclusions to the applicability section of the proposed standard to ensure that PRC-030 R1 does not include balance of plant (BOP) Protection Systems already covered under PRC-004-6. WEC Energy Group supports all NAGF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	MRO-NSRF_2023-02-PRC-030_UCF_04-17-2024_FINAL.docx
Comment	
· §4. Applicability The MRO NSRF reiterates its recommendation that the SDT add exclusions to the applicability section of the proposed standard to ensure that PRC-030 R1 does not include balance of plant (BOP) Protection Systems already covered under PRC-004-6. An example would be PV & wind generation	

34.5kV collection system Protection Systems. As the proposed standard is currently drafted there is no clear distinguishing language. It is suggested that the footnote information be included in the §4. Applicability to eliminate the footnote altogether.

· Requirement R1:

The MRO NSRF would like to reiterate that Requirement R1 “documented process to identify unexpected changes” is not a requirement within the SAR’s scope. According to the SAR, Generator Owners need to “analyze performance issues identified at their facilities”. Having a documented process is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit.

It is suggested that the footnote information be included in the bullet of R1 to eliminate the footnote altogether.

In R1, suggest the deletion of the word “documented”

In M1, suggest that item 1 be changed from “(1) the documented process...” to “(1) implementation of a process for...”.

With the two changes above deleting “documented”, suggest that item (2) in M1 be deleted.

· Requirement R2:

The MRO NSRF does not agree with allowing the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA) to be able to request an analysis of any a change in “the inverter-based resource(s) active power output”; the criteria for this analysis shall be the same criteria as outlined in Requirement R1.

The MRO NSRF does not agree with the 90 calendar day timeframe and believes it should be 120 days similar to PRC-004-6.

In the new R2, R2.1.1, suggest being more direct by changing “Determination of the root cause(s)...” to “Determine the root cause(s)..”.

In the new R2, R2.1.2, suggest being more direct by changing “Documentation of the facility’s...” to “Document the facility’s...”.

In the new R2, R2.1.3, suggest being more direct by changing “Assessment of any performance...” to “Assess any performance ...”

In the new R2.1.3, suggest changing the word “needed” to “indicated” to take into account the possibility of there being no changes available to affect the response of the IBR controls to the system disturbance.

In the new R2, R2.1.4, suggest being more direct by changing “Determination of the susceptibility...” to “Determine the susceptibility...”.

· Requirement R3:

The MRO NSRF would like to reiterate that being required to provide either a 'Corrective Action Plan or justification of why corrective actions will not be applied to the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA)' is not a requirement within the SAR's scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit, if the RC, BA & TOP do not need or want this data & analysis.

· Requirement R4.3:

The MRO NSRF would like to reiterate that the proposed Requirement R4.3 is not a requirement within the SAR's scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit, if the RC, does not need or want this information.

· Requirement R1 & R2

The MRO NSRF would also like to reiterate that most inverter based resources are owned by independent power producers (IPP), as such, it is their best interest to ensure a high availability of the Facility and analyses such as the ones being proposed in PRC-030 are not only in the interest of reliability, but also in the interest of the IPP so long as the criteria for performing an analysis is reasonable and cost effective. The MRO NSRF appreciates the efforts the Standards Drafting Team has put forth and is suggesting the following criteria for the proposed PRC-030 analysis based on the aforementioned information:

Removal of Requirement R1 in its entirety and combining it with the proposed Requirement R2 as follows:

R2. Each applicable Generator Owner, within 120 calendar days of either a, capability1 change of greater than 20% of the generation Facilities gross capability1 nameplate or following a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a capability1 change of greater than 20% of the generation Facilities gross nameplate capability1, shall, excluding:

· Changes associated with intermittent primary energy source (fuel supply: wind, solar irradiance) availability;

· Resource dispatch, resource ramping, planned outages, or planned resource testing; or

· Loss of Transmission Provider's interconnection facilities.

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in capability1;

2.1.2. Document the Facility's Ride-through performance including reactive power response during the event;

2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the susceptibility of its other inverter-based resource facilities to similar events.

2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator.

1: A generation resource capability is based on availability of individual generating units that compromise the Facility multiplied by the individual generating unit's nameplate.

Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	

Document Name	
Comment	

EEI offers the following suggested changes to PRC-030-1:

General Comment: Throughout this Reliability Standard there is use of non-glossary terms where glossary terms are available and should be used. (e.g., active power vs. Real Power) 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.

Applicability Section Comments:

Footnote 1: EEI does not support Footnote 1 because it expands the definition of IBRs beyond what was recently approved by the industry, noting the footnotes expansions the definition of IBR 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 Footnote 1 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 submitted to the industry that defines the issues and risks to BPS reliability that VSC-HVDC systems pose. Lastly, this project has been aligned with FERC Order 901, noting that IBR related performance requirements for ride -through are to be completed and submitted to FERC by Nov. 4th. Yet, the DT expands the definition of IBRs by adding VSC-HVDC systems complicating industry approval without any technical justification for expanding the definition.

Requirements Comments:

Requirements R2 & R3: EEI is concerned with the inclusion of requirements that are not clearly defined or sent from multiple registered entities (i.e., RC, BA 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 actually responsible. (See Requirement R2) 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 R3) We further note that none of the entities identified (i.e., RC, BA, or TOP) are identified within the Applicability section of this proposed Reliability Standard. Yet, all of this places considerable compliance burdens on the IBR-GOs who will need to analyze and resolve (R2) those issues at the request of any of these entities and provide notification regarding CAP or technical justification, regarding their inability to fully resolve the issues, without any of these entities having clearly defined responsibilities within this standard.

Requirement R4, Subpart 4.3: EEI suggests adding “Upon Request” to Subpart 4.3 for consistency with Requirement R2, Subpart 2.2 because there should not be a regulatory requirement to notify the RC regarding CAP actions, timetables change and when the CAP is completed, unless the RC specifically requests that the GO provide such notification.

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	
R2.1- Identifying the root cause of the event and determining the corrective actions required will likely require the IBR manufacturer's collaboration. How can this be done if the manufacturer has gone bankrupt or is unwilling to collaborate. Please indicate what to do for such a situation. R2.2 - Why provide the analysis results only if requested. Every analyzed problematic situation report should be transmitted. R3 - The first bullet, when the CAP identified required modifications to the IBR, should require the OEM to inform all GO using the same technology a CAP is required for their facility.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
WECC believes footnote 1 is not cohesive with the phrase to which it is attached and should be removed as it has no bearing or context within this Standard. Evidence Retention Section needs some adjustments as there are possible differences in the retention requirements for R2 materials. The first bullet indicates saving R2 material for 36 calendar months AFTER completion of the Requirement. The second bullet indicates saving R2 material for "36 calendar months following the completion of each CAP, completion of each evaluation, and completion of each declaration". WECC suggests the following: "The Generator Owner shall keep data or evidence of Requirement R1 Measure M1 for 36 calendar months. The Generator Owner shall keep data or evidence of Requirement R2 Measure M2 and Requirement 3 Measure M3 for 36 calendar months after the development of a Corrective Action Plan. The Generator Owner shall keep data or evidence of Requirement R4 Measure M4 for 36 calendar months after changes in any Corrective Action Plan actions or timetables or completion." Severe VSL for R2 needs to capitalize "Ride-through". VSLs for Requirement R3 need to consistently use "calendar days" as called out within Requirement R3. Consider moving the timeframe to alleviate concerns about "implementation"—Example "The responsible entity failed, within 60 to 90 calendar days, to develop a CAP or provide a technical justification addressing why corrective actions will not be applied nor implemented." Without any time requirement to complete a CAP and an evidence retention timeframe of 36 calendar months, how would anyone ascertain the CAP was not implemented if the timeframe went past 36 calendar months for completion of activities? Technical Rationale. At the top of page 2 the sentence "Requirement R3 requires a Corrective Action Plan (CAP) or technical justification when corrective actions are needed" should be adjusted to say "….when, respectively, corrective actions are needed or will not be applied nor	

implemented". As currently written the latter part of sentence does not appear correct. The Figures should reflect "calendar days" not simply days. Figure 1.2 indicates a change greater than 20 MVA but Requirement R1 language indicates 20 MWs. MVA is a common SCADA-driven point (Facility Ratings are provided in MVA and regularly evaluated by every major EMS vendor for powerflow analysis.)

The exclusions included in Requirement R1 should be in Requirement R1 flow. Consider a decision box under the "10%" that shows "Exclusions in R1" with a flow to "Non-applicable Event". In the Requirement R2 section there should be a Yes path from "Unexpected Performance" to a new box "Performance issues and Corrective Action identified" with a Yes path to R3 and a No path to "No mitigation". Note the rigor of analysis could come into question if an event occurred and the analysis did not identify any corrective actions. Changes to "calendar days" should be made to reflect the Requirement language. "Ride-through" should be hyphenated (page 5 second paragraph.) The Technical Rationale uses the more acceptable language regarding applicability to other units versus the ambiguous "determination of the susceptibility" language within the Standard. Under requirement R3 the sentence "When the IBR Performance issue cause(s) is identified in Requirement R2 or Requirement R3 requires Generator Owner(s) to develop a CAP or provide a technical justification that addresses why corrective actions will not be applied nor implemented" is not a well-developed sentence. Should "or" be removed after "R2"? There is reference to development of multiple CAPs for multiple causes which is valid. However, the analysis must be complete within 90 calendar days and the CAP(s) completed within 60 calendar days of completion of the analysis.

Interconnection requirements historically did not reach the detailed level that analysis of events have revealed. Indicating that older interconnection requirements are a technical justification not to address issues effectively grandfather's the risk into the ecosystem providing for continued unreliable operations. By doing so, this Standard is not mitigating the risk identified. Additionally, "material modifications" is a term that was written out of FAC-001/002 and should not be used. A technical justification is equipment limitations (not interconnection requirements). Operating limitations should be placed on IBRs not able to meet current interconnection requirements to mitigate the risk posed.

Technical Rationales are to provide reasons why language was provided and not ways to be compliant. The technical justification is more of Implementation Guidance language than a Technical Rationale. While WECC agrees that there may be technical justifications provided, the first example in the Technical Rationale is not technical in nature. If an inverter-based resource could technically not adjust a setting, that would be a technical rationale (and justification).

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), North American Generator Forum (NAGF), and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 4

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1, Group Name Exelon

Answer	
Document Name	
Comment	

Exelon agrees with the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE has the following additional comments:

- Requirement R2, subpart 2.2 seems to require that an additional request be made by the RC, BA or TOP for the analysis results. Texas RE recommends the phrase "upon request" be removed from subpart 2.2. Please see the revision below (in bold).

2.2. **Upon request,** p**rovide** the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator

- Technical Rationale – The Figure 1.2: PRC-030-1 Flowchart should be revised to reflect the 20 MW requirement instead of 20 MVA.
- Technical Rationale - On Figure 1.2: PRC-030-1 Flowchart: Texas RE recommends adding a line from Technical Justification box to a new box "Notification to RC, BA, TOP" to match Requirement R3.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
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: *Requirement R2:* *The NAGF notes that any IBR data request initiated by the Reliability Coordinator (RC), Balancing Authority (BA), and/or the Transmission Operator (TOP) should be contained in its respective data request processes under IRO-010 and TOP-003.* *Requirement 2.1.2: The NAGF recommends that this requirement should be included as part of the process created in Requirement R1. In addition, the NAGF is concerned with the potential for overlap with PRC-029.* *Requirement R3: The NAGF seeks clarification as to why the Generator Owner must provide a CAP or technical justification to the RC, BA, and TOP.* *Requirement R4.3: The NAGF recommends that the DT consider removing the requirement to notify the applicable Reliability Coordinator if CAP actions or timetables change and when the CAP is completed. To the extent the RC wants this information, they should request it under their data specification under IRO-010.*	
Likes 2	JEA, 1, McClung Joseph; Scott Brame, N/A, Brame Scott
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	

Under the Facilities Applicability, Section 4.2.1 states “BES inverter-based resources” and the word “resources” is annotated by Footnote 1. Footnote 1 states “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.”

SMUD believes Footnote 1 is incorrect. Did the Standard Drafting Team (SDT) intend to word Footnote 1 in this manner, or should it be worded similar to Footnote 2 in the latest version of PRC-029-1 which states “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.”

It seems that Footnote 1 in the latest version of PRC-030-1 has been copied in error from PRC-028-1 Draft 3 Footnote 2, which does reference “main power transformers”.

Rather than using the term “BES inverter based resources” and defining “inverter based resources” with a Footnote, SMUD recommends that the PRC-030-1 SDT coordinate with the SDTs for PRC-028-1 and PRC-029-1, and use the glossary term IBR and its definition approved by industry on March 8, 2024 under Project 2020-06. This will ensure accuracy and consistency across all 3 Standard Projects regarding Facilities Applicability and IBRs.

Likes 1	JEA, 1, McClung Joseph
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 both the NAGF and EEI additional comments for PRC-030-1.

Those comments are as follows:

NAGF provided the following comments: *For Requirement 2, the NAGF notes that any IBR data request initiated by the Reliability Coordinator (RC), Balancing Authority (BA), and/or the Transmission Operator (TOP) should be contained in its respective data request processes under IRO-010 & TOP-003.   Requirement 2.1.2: The NAGF recommends that this requirement should be included as part of the process created in Requirement R1. In addition, the NAGF is concerned with the potential for overlap with PRC-029.*

Requirement R3: The NAGF seeks clarification as to why the Generator Owner must provide a CAP or technical justification to the RC, BA, and TOP.

Requirement R4.3: The NAGF recommends that the DT consider removing the requirement to notify the applicable Reliability Coordinator if CAP actions or timetables change and when the CAP is completed. To the extent the RC wants this information, they should request it under their data specification under IRO-010.

EEI - General Comment: Throughout this Reliability Standard there is use of non-glossary terms where glossary terms are available and should be used. (e.g., active power vs. Real Power) 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.

Applicability Section Comments:

Footnote 1: EEI does not support Footnote 1 because it expands the definition of IBRs beyond what was recently approved by the industry, noting the footnotes expansions the definition of IBR 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 Footnote 1 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 submitted to the industry that defines the issues and risks to BPS reliability that VSC-HVDC systems pose. Lastly, this project has been aligned with FERC Order 901, noting that IBR related performance requirements for ride -through are to be completed and submitted to FERC by Nov. 4th. Yet, the DT expands the definition of IBRs by adding VSC-HVDC systems complicating industry approval without any technical justification for expanding the definition.

Requirements Comments:

Requirements R2 & R3: EEI is concerned with the inclusion of requirements that are not clearly defined or sent from multiple registered entities (i.e., RC, BA 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 actually responsible. (See Requirement R2) 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 R3) We further note that none of the entities identified (i.e., RC, BA, or TOP) are identified within the Applicability section of this proposed Reliability Standard. Yet, all of this places considerable compliance burdens on the IBR-GOs who will need to analyze and resolve (R2) those issues at the request of any of these entities and provide notification regarding CAP or technical justification, regarding their inability to fully resolve the issues, without any of these entities having clearly defined responsibilities within this standard.

Requirement R4, Subpart 4.3: EEI suggests adding “Upon Request” to Subpart 4.3 for consistency with Requirement R2, Subpart 2.2 because there should not be a regulatory requirement to notify the RC regarding CAP actions, timetables change and when the CAP is completed, unless the RC specifically requests that the GO provide such notification.

Likes 0	
Dislikes 0	
Response	
Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

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

It does not appear that the text of footnote 1 aligns with the body text for the term “inverter-based resources (IBR)”. That footnote text should be updated accordingly to match the intended definition. However, creating a new definition for “inverter-based resources” for this standard (and PRC-028 and PRC-029) 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

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	
Document Name	

Comment

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.”

It is imperative that the standard drafting teams for this project as well as the 2021-04 (PRC-002 and PRC-028) and 2020-02 (PRC-029 and PRC-024) assure a coherent way of addressing the inclusion and exclusion of IBRs in current and upcoming standards. These three different projects have all used different ways of drafting up section 4.2 of the standard.

The following comments are specific to PRC-030-1, Requirement R1 :

- Add an exclusion for active power changes linked to frequency regulation and power limitations/runback ordered by the TO.
- Add an exclusion for faults inside the IBR plant.

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	
Comment	
Some criteria should be added to the RA/BA/TOP request for analysis under R2. AES CE does not believe that an analysis for changes below the thresholds in R1 should be included in the requirement, even if requested by the RA/BA/TOP.	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
Tri-State supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Brian Lindsey - Entergy - 1	
Answer	
Document Name	
Comment	
R2. Data quality concern in an event happening in 4 seconds and being able to complete the analysis. Concerns with having to provide the information to multiple entities. R3 and R4: Have a concern with multiple entities requesting information and a single POC would be more efficient. Should be no need to provide CAP to other entities unless explicitly requested.	

The action to create the Corrective Action Plan should 90 days instead of 60 days. Recommend adding language in R3 that states that if all actions are completed during the analysis phase to correct the issue there will be no need for a CAP.

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 suggested changes to PRC-030-1:

General Comment: Throughout this Reliability Standard there is use of non-glossary terms where glossary terms are available and should be used. (e.g., active power vs. Real Power) 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.

Applicability Section Comments:

Footnote 1: EEI does not support Footnote 1 because it expands the definition of IBRs beyond what was recently approved by the industry, noting the footnotes expansions the definition of IBR 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 Footnote 1 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 submitted to the industry that defines the issues and risks to BPS reliability that VSC-HVDC systems pose. Lastly, this project has been aligned with FERC Order 901, noting that IBR related performance requirements for ride -through are to be completed and submitted to FERC by Nov. 4th. Yet, the DT expands the definition of IBRs by adding VSC-HVDC systems complicating industry approval without any technical justification for expanding the definition.

Requirements Comments:

Requirements R2 & R3: EEI is concerned with the inclusion of requirements that are not clearly defined or sent from 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) 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 R3) 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 places considerable burden on the IBR-GOs that needs to be resolved and clarified.

Requirement R4, Subpart 4.3: EEI suggests adding "Upon Request" to Subpart 4.3 for consistency with Requirement R2, Subpart 2.2 because there should not be a regulatory requirement to notify the RC regarding CAP actions, timetables change and when the CAP is completed, unless the RC specifically requests that the GO provide such notification.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation supports NAGF comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment

Constellation supports NAGF comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	

Document Name	
Comment	

R3 currently reads "… develop one of the following and provide it to the applicable Reliability Coordinator, Balancing Authority, *and* Transmission Operator." Shouldn't this say "…Reliability Coordinator, Balancing Authority, *or* Transmission Operator"? (Same with M3.)

R4.3 should also require notification "to each the applicable Reliability Coordinator, Balancing Authority, or Transmission Operator" rather than only to the Reliability Coordinator.

Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	
Comment	

FirstEnergy believes that the request for information to and from an IBR Owner may require a full 120 days similar to PRC-004 (understanding IBR's are excluded from PRC-004). We therefore are asking the DT to consider matching the timeframe for PRC-030 with that of PRC-004. This would also provide consistency throughout the industry and eliminate confusion between these two standards.

We also suggest that the third criteria under R1 be changed from "Transmission Provider's" to "Transmission Service Provider" noting that Transmission Provider is not a defined term in the NERC Glossary.

Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5

Answer	
Document Name	
Comment	

As AEP stated in the previous ballot period, the scope and general intent of PRC-030 appears reasonable, but the process and flow are flawed and needs to be changed. While it might be reasonable to simply identify the "event" within 90 days (or 120 days to match PRC-004), additional time will still be needed to research and determine the root cause(s). This could conceivably take 90 days or more, especially if support is needed from the OEM. And once the cause is determined, at least 60 additional days (to match PRC-004) would then be needed to develop the CAP and document the Applicability (R2.1.2) of that CAP to other facilities. Applicability cannot be documented without first determining the root cause and then possibly developing the CAP. It cannot be assumed that a root cause will be found in every case, and the standard needs to allow for this. To further illustrate our concern, the standard drafting team provided this response to AEP comments: "The Drafting Team believes it should be up to the GO to develop a process to identify and analyze events. Requirement R2 makes it clear that they have 90 days from the date of the event to complete analysis, regardless of when the event was identified. They also have 90 days to complete analysis of events identified by the BA, RC, or TOP from the date they were notified of the event." AEP understands this response, however the revisions to the standard do not match this response. Specifically, "that they have 90 days from the date of the event" is not what is written in R2. R2 presently reads "within 90 calendar days of identifying an active power change event", which has a different meaning. AEP agrees that it should be measured from the date of the event, not the date of identifying an event. One related gap, as we see it, is that it is not explicitly clear how many days are afforded to identify an event, though 90 days are inferred. These collective concerns are the primary driver behind our decision to vote negative on PRC-030.

The proposed version of PRC-030 makes the assumption that a root cause will be found in every case, but this is not realistic. The standard must be revised to accommodate for situations where a root cause(s) is never found or identified.

AEP would like to see the timelines align with those used in PRC-004, where appropriate.

It might be advantageous for a flowchart to be added to the Technical Rationale document. In that light, AEP reads the present structure for R2/R3 as follows:

After R2 Event identification date or Event Notification date occurs, will within 90 days perform the following:
1) Determine root cause of change in power output
2) Document plant ride-through performance for the event
3) Assessment of any performance issues and if any corrective actions are needed
4) Determine susceptibility of other IBRs to similar events (applicability)
After these are accomplished, then proceed to R3 obligations to develop CAP or make No CAP declaration.

In addition, AEP would prefer the proposed structure for R2/R3 to be as follows:
R2:
1) Event date or Event Notification starts process to complete the following within 120 days of the Event or within 60 days of Event Notification, whichever is later
a) Document plant ride-through performance for the event and
b) Assessment of any performance issues and if any corrective actions are needed
2) R3: Once the Root Cause is found/identified, the following must be accomplished within 60 days:
a) Determine susceptibility of other IBRs to similar events (applicability)
b) Develop CAP or make a No CAP Declaration

The new footnote 1 is problematic, as it does not appear to correlate with the IBR. We believe its inclusion may have been unintentional.

R2 and R3 include the word "applicable" when referencing the RC, BA, and Transmission Operator, however we believe this word is misleading and may be interpreted inconsistently. As a result, we recommend removing this word from R2 and R3.

Likes 0	
Dislikes 0	

Response

Bruce Walkup - Arkansas Electric Cooperative Corporation - 6

Answer	
Document Name	

Comment

R2 and R3 should allow for extended time periods for analysis and implementation. The quantity of events triggers R1 will create and require to be looked at is going to be staggering and if an update is required, the time required to implement them in a large-scale plant could be hard to meet.

Likes 0	
Dislikes 0	

Response

Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3

Answer	
Document Name	

Comment

SMEs responded with the following “R2 and R3 should allow for extended time periods for analysis and implementation. The quantity of events triggers R1 will create and require to be looked at is going to be staggering and if an update is required, the time required to implement them in a large-scale plant could be hard to meet.”

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4

Answer	
Document Name	

Comment

The Drafting Team has a challenging task of meeting a FERC directive, yet creating a standard that is acceptable to the affected entities. It is in the best interest of the industry to focus on performance metrics, and not administrative compliance for ensuring there are processes and plans. This has the added advantage of allowing each entity to implement the best solutions for their unique needs.

Likes 0	
Dislikes 0	

Response

Consideration of Comments

Project Name:	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues | Draft 2
Comment Period Start Date:	6/7/2024
Comment Period End Date:	7/10/2024
Associated Ballot(s):	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Implementation Plan AB 2 OT 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues PRC-030-1 AB 2 ST

There were 49 sets of responses, including comments from approximately 152 different people from approximately 101 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) 446-2564.

Questions

1. Does the entity believe there should be any proposed changes in the thresholds in Requirement R1?

2. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

3. Does the entity have any concerns regarding the 2023-02 Implementation Plan? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

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
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,SPP RE,WECC	SRC 2024	Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	1	WECC
					Helen Lainis	IESO	1	NPCC

					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
Exelon	Daniel Gacek	1		Exelon	Daniel Gacek	Exelon	1	RF
					Kinte Whitehead	Exelon	3	RF
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			Micah Runner	Black Hills Corporation	1	WECC

				Black Hills Corporation - All Segments	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	1	NPCC

						Edison Co. of New York		
					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
					Nicolas Turcotte	Hydro-Quebec (HQ)	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	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion	3	NA - Not Applicable

Resources, Inc.						Resources, Inc.		
					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 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 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. Does the entity believe there should be any proposed changes in the thresholds in Requirement R1?

Kim Thomas – Duke Energy	
Answer	No
Document Name	(if an attachment is provided by submitter)
Comment	
None	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
Thank you for the comment.	

Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	No
Document Name	
Comment	
SMEs responded with the following: “If this standard is enacted the threshold should be high to trigger events. There are too many variables to reliably screen out excluded events so a significant amount of time will be required just to determine if events should be analyzed.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment.	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	No
Document Name	
Comment	
If this standard is enacted the threshold should be high to trigger events. There are too many variables to reliably screen out excluded events so a significant amount of time will be required just to determine if events should be analyzed.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy has no issue with the proposed changes to the threshold in Requirement R1.	
Likes 0	
Dislikes 0	
Response	

Thank you for the support.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see the response to EEI’s comment.	
Patricia Ireland - DTE Energy - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2024	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment.	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
In reading the Technical Document in context with the question there seems to be some inconsistency. The Technical Document uses the terms “sudden changes in active power” and “unexpected”, however R1 has been edited to state “changes in active power output”. This can be interpreted to refer to “any changes inactive power output”. This is overly broad and can be misapplied. Further, the requirement refers to “Examples including changes in wind, solar irradiance”. If R1 is deemed a valid requirement then the process should focus on early detection and notification/communication. Documented processes for equipment failures or predicted longer term weather events seems more practicable. Most importantly unexpected, unwarranted or unreliability performance should require a process to analyze the root cause and correct deficiencies. The Drafting Team should focus on the stated purpose of the SAR: “The scope of this project is to either create a new NERC reliability standard or modify an existing standard that requires IBRs that respond to grid disturbances in an unexpected, unwarranted, and unreliable manner to identify, analyze, and mitigate performance issues that occur within the facility. This includes any types of protections or controls that result in abnormal performance issues within the plant, including abnormal performance resulting in anomalous behavior of active power output from the facility during events.” The wording of R1 does not support this statement of the scope of the project from the SAR. The Drafting Team should be more assertive in requiring GOs with IBRs to perform to a defined set of criteria to remain compliant. This includes full event analysis and root cause investigations where they violate performance criteria. Criteria can be softened so they do not have to perform perfectly 100% of the time, but there should be a threshold for performance.	
Likes 0	
Dislikes 0	
Response	

Use of the terms sudden and unexpected led to much uncertainty and discussion as to how that would be applied consistently. Therefore, the DT chose to bound the initial change at event onset to a four second timeframe. Change is a broad term and that is why the DT set a minimum change threshold of 20 MW with a 10% change requirement as well. R2 address root cause in 2.1.1. This standard requires detection, analysis, and corrective actions for performance outside the Reliability Standards requirements. This standard does not set the requirements, but requires the plant compare its response to the requirements. Per NERC limitations, one standard cannot refer to other standards.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Dominion Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response to EEI's comment.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP supports the SDT's recommended threshold values in Requirement R1, however it is not explicitly stated in R1 where the measurement needs to be taken. AEP suggests adding the text "individually, at each MPT level" or some other defined point.	
Likes 0	
Dislikes 0	

Response	
It is the DT expectation that the change would be at the IEEE 2800 RPA. While that is typically the POM, it can be at other locations. At this point in the process, with limited time for review and comment, the DT did not make additional changes.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Our concern here is if there is a fault on the system there will be a momentary reduction in power output and it takes time (~ less than 500ms) for the output to return to steady state. Our main problem with the standard is all the burden is on the IBR GO, GOs would be required to evaluate “any” power loss event that is not excluded which is unnecessary in my opinion . Unless a facility fails to ride through a system disturbance then failures or issues at an individual site will probably not have much of an impact on the BES. Failures during ride through events should be evaluated.	
Likes 0	
Dislikes 0	
Response	
If the facility output changes and then returns to pre-even levels within 4 seconds (dip and return), then the standard considers that event, by default, to be expected behavior. While there could be some valid events to evaluate within this time period the standard does not currently require the GO to investigate these. The standard is, in part, looking for fast power changes with output changes that persist for many seconds.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

The requirement mandates "a documented process to identify changes in active power output that are the greater of 10% of the plant's gross nameplate rating or 20 MW." The BES definition's lower limit is 20 MVA. Therefore, assuming 100% PF, a unit at this lower limit would basically have to be totally lost in order for this requirement to come into play. On the flipside, take a 1,000 MVA plant - again, assuming 100% PF, it would have to lose (or gain) 100 MW for the requirement to be applicable. Is this the SDT's intent? If so, that's a pretty wide difference. If not, seems like the requirement's wording should be lower rather than greater.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the DT having a base floor of 20 MW, and 10% plants nameplate from that level on up.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation supports NAGF comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Please see the response to NAGF's comment.	
Alison MacKellar - Constellation - 5	
Answer	Yes

Document Name	
Comment	
Constellation supports NAGF comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Please see the response to NAGF’s comment.	
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: Comments: EEI appreciates the DT’s efforts to set reasonable and workable thresholds for IBR GOs, however, we are concerned that photovoltaic (PV) plants could potentially be over burdensome administratively given the identified threshold for Real Power output changes of 10% of the plant’s nameplate (or 20MW) over a 4 second period. While we understand why the DT chose the 4 second time period, we have no data to validate this is sufficiently narrow to avoid confusing changes in solar irradiance with a plants response to a system disturbance. We further note that for very large PV Plants, this threshold is likely sufficient, but we are concerned that smaller plants could be negatively impacted. To address this concern, we ask that the DT, NERC or one of the technical committees develop an investigation and written technical justification to support the proposed threshold and or consider consulting with NREL or EPRI to validate the veracity of the proposed threshold.	
Likes 0	

Dislikes 0	
Response	
Please see the response to EEI's comment.	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
R1. A 10% change in the active power output is too low and not the right metric. There are likely to be 10% changes that are not attributed to system disturbances which impact the plant operation, especially for wind or solar. The value should be raised back up to a 20% change. The cost of analyzing every 10% change is not commensurate with the benefit and does not focus on the intent of the SAR. The Standard should focus on the loss of individual generating units not on balance of plant protection systems.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the DT will consider this change. The team will also include reasoning in the Technical Rationale (TR) for coming up with these thresholds.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Avista agrees with the EEI Near Final Draft comments and concerns discussed in the draft comments.	
Likes 0	

Dislikes 0	
Response	
Please see the response to EEI’s comment.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
TEPC agrees with EEI's comments asking for a technical justification to support the proposed threshold.	
Likes 0	
Dislikes 0	
Response	
Please see the response to EEI’s comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Tri-State supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Please see the response to MRO's comment.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
AES CE believes that the extension of the 2 second duration in R1 to 4 seconds will introduce a significant amount of new events requiring analysis and does not align with the Technical Rationale language that "The intent is to exclude from review slow power changes expected with normal operations".	
Likes 0	
Dislikes 0	
Response	
The expectation of the DT is that GO will use SCADA to identify these events and perform the initial screening of expected events excluded by R1. Therefore, the DT does not want to make the time so short that more advanced monitoring capability is required. While extending the timeframe from two seconds to four seconds will include events that change marginally slower, the DT believes that changes over four seconds are still short enough to qualify as fast.	
Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
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. We support the goals of this standard to analyze and mitigate IBR performance issues; however, the standard as written would require significant analysis of events where IBR facilities respond to grid events *correctly*. This would not be cost effective and not aligned with	

the intention of the SAR as written. The major driver for this is the trigger criteria defined in Requirement R1. Requirement R1 defines the changes in active power output "occurring within a four-second period." The "within four-second period" characterization may miss controller oscillations, control interactions, and slower active or reactive power responses in the wrong direction than intended. It would also pick up all types of dynamic events of an IBR facility, including events where an IBR facility performs correctly. This would lead to detailed forensic event analysis for almost every type of grid event rather than only those events where abnormal performance occurred.

Providing guidance in Requirement R1 for the trigger of the events of concern is a good practice but limiting the requirement language to specify only one trigger (e.g., the "changes in active power output occurring during a period that is no longer than 4 seconds") to capture any type of unexpected changes with an IBR could result in certain types of events being missed while also capturing many events that don't need to be analyzed (e.g., correct/intended responses of an IBR). The recommendation would be to include a set of event triggers as sub-requirements under Requirement R1.

Example triggers could include:

(1) ***Unexpected*** changes in active or reactive power output within a four-second period

(2) ***Unexpected*** changes in active or reactive power output ***longer*** than a four-second period, including momentary cessation, partial or full IBR tripping, or detailed recovery of active power response post-fault

(3) Active or reactive power oscillations that are poorly damped or persist for longer than *[consider value]* seconds

This structure would give the opportunity for additional triggers to be easily added and implemented/considered to more suitably capture unexpected operations occurring from IBRs on the BPS.

If additional trigger criteria are not used, another approach would be to modify the existing "within four-second window" criteria by adding additional SCADA scan rate samples into the existing trigger. Specifically, this would ensure that correctly performing dynamic events would ***not*** be considered within scope, and rather only significant power output changes that are sustained (i.e., trip of an IBR, active power output jump up/down that remains longer than a dynamic event such as momentary cessation or delayed power recovery, etc.). This would align with the language in the SAR to identify IBRs that incorrectly perform during dynamic grid events by either tripping, reducing active power, and not returning to pre-event output levels within 1-second.

Example criteria language for Requirement R1 along these lines could be:

"Changes in active power output that are the greater of either 10% of the plant's gross nameplate rating, or 20 MW, and the change in active power output remains at the new value for two or more consecutive SCADA scan rates [or could say remains at the new value for 2 seconds or longer]." In addition, the drafting team should consider modifying Requirement R1 and Requirement R2 so that changes in power output are not limited to just active power, but also reactive power. In fact, Requirement 2.1.2 highlights documentation a facility's ride-through performance including reactive power responses during grid events.	
Likes 0	
Dislikes 0	
Response	
At one point, the DT had statements very similar to those proposed. Use of the terms sudden and unexpected led to much uncertainty and discussion as to how that would be applied consistently. Therefore, the DT chose to bound the initial change at event onset to a 4 second timeframe. The 4 seconds is a limit on the amount of time within which the change is calculated, it is not the entire event timeframe. The 4 seconds is a guideline as to what a fast or sudden change is. It has no meaning or application to how long the event or response lasts in total. The DT recognizes that criteria to capture every type of event would require very complicated and detailed triggering specifications. The DT did not feel that was a practical objective, particularly given the time constraints for standard development. While the proposed criteria will certainly provide some false positives and miss some relevant events, the DT feels this criterion is balanced and adequate to detect the majority of events when the plant may have performed unexpectedly. While not specifically included, the DT expects that the enumerated evaluations would be performed as part of R2.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Yes, Black Hills Corporation feels changes are needed for Requirement 1. We are concerned for small photovoltaic (PV) plant could potentially be overburdened administratively given the identified threshold for Real Power output changes of 10% of the plant's nameplate (or 20 MW) over a 4 second period. We further note for very large PV plants, this threshold is likely sufficient. Black Hills Corporation requests clarification as to the basis/justification for the 4 second event threshold. Request the SDT Team to consider	

increasing the 4 second event threshold to capture only those Inverter-Based Resource (IBR) events that have a meaningful impact on the BPS.	
Likes 0	
Dislikes 0	
Response	
These Requirement R1 comments are addressed in previous comments on the topic.	
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	
SMUD supports the comments submitted by AES Corporation.	
Likes 0	
Dislikes 0	
Response	
Please see the response to AES Corporation.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	

The NAGF requests clarification as to the basis/justification for the 4 second event threshold identified in Requirement R1. The NAGF requests the Drafting Team to consider increasing the 4 second event threshold to capture only those Inverter-Based Resource (IBR) events that have a meaningful impact on the BPS. In addition, the NAGF notes that the event identification and post-event performance validation process will largely be a manual labor-intensive process. Setting the right thresholds to only identify IBR events that have a meaningful impact to the BPS will help ensure optimal use of GO staff resources when identifying/analyzing such events.	
Likes 2	JEA, 1, McClung Joseph; Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
The recent industry events have a power change within a short timeframe and the DT believes the 4 seconds will identify meaningful events that have impact on BPS reliability.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response to MRO NSRF's comment.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	

Comment	
We agree with the EEI's comments and concerns discussed in their comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response to EEI’s comment.	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Please see the response to EEI’s comment.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Avista agrees with the EEI Near Final Draft comments and concerns discussed in the draft comments.	

Likes 0	
Dislikes 0	
Response	
Please see the response to EEI’s comment.	
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), North American Generator Forum (NAGF), and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 1	
Likes 0	
Dislikes 0	
Response	
Please see the responses to EEI’s, NAGF, and MRO NSRF’s comments.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
WECC believes the second draft is better developed but the risk is not being effectively mitigated. Leaning heavily on a GO analysis to develop a CAP OR provide a technical justification. And one of the "technical" justifications provided indicated the IBR was connected under old interconnection requirements (effectively grandfathering in everyone!). Also very concerned about the Implementation Plan	

that hinges on PRC-028 and PRC-029--Really need a complete diagram of the expectations of all 3 Standards (and the others associated with the Projects). PRC-028 is basically not completely effective until 2030. There is not a defined term that matches “Transmission Provider”. Did the DT mean “Transmission Service Provider (TSP)”? As such, a TSP may not own any interconnection (e.g., ERCOT is the only TSP in the Texas Interconnection and has no interconnection facilities.) This needs to change to Transmission Owner(s) to be clear. WECC appreciates the DT’s approach to implementing a “documented” process. There are some discussions being held in the industry that mentioned removal of “documented” for compliance risk concerns. There is a bigger reliability risk without documented procedures to guide mitigation of the risks proposed by this Standard and others. It should be clear that R2 allows the RC, BA, or TOP to identify a Disturbance and a change in the inverter-based resource active OR reactive output and the GO should analyze the issue. This should not limit the RC/BA/TOPs to pursue IBR related events EVEN those not meeting the criteria for a GO to self-identify. Requirement R2.1 uses “IBR” versus “inverter-based resource” (as used in Requirement R2.1.4). It should be clear that if a RC, BA, or TOP provides a “request” trigger for actions a GO shall perform, per the base language in Requirement 2, there is not a need to “request” the output of the analysis in Requirement 2.2. Easily see an entity not retaining evidence to clearly demonstrate provision of the analysis indicating there was not a request for said analysis. Why would a RC, BA, or TOP simply request an analysis if the analysis would not be provided? The Technical Rationale indicates “some events would only be identified by one entity” while the Requirement is clear the GO must have a process to identify and the RC/BA/TOPs is limited in some respects under this Requirement. Suggest dropping “Upon request” at the start of Requirement R2.2. Setting the trigger off the gross nameplate value may mask significant events. The PV example 2 exhibits a 30% drop in Real-time output yet does not qualify. If other PV facilities are experiencing the same output level (75% of gross nameplate) because the time of day and an event occurs that drops 30% of all the inverter-based resources in the area, no self-analysis of the event is required. Consider changing the criteria to Real-time output to fully capture the risks. “Ride-through” should be listed as a term here with references to the Project proposing the definition (understand the Implementation Plan mentions approval of Prerequisite Standards.) There is no clarity in what “susceptibility” means in this context. The previous language regarding applicability should be retained. How will an entity demonstrate its determination of susceptibility? If an entity identifies NO performance issues and no corrective actions based on its analysis, how does that get communicated to the RC/BA/TOP? If the rigor of analysis dictates the path forward in the Standard (i.e. development/Implementation of a CAP) what incentives a GO to provide rigor in the analysis? Does the RC/BA/TOP have any mechanism to require corrective actions after a review of the analysis? Requirement R3 should use numbered bullets for consistency. The first bullet in Requirement R3 correctly addresses other applicable facilities but incorrectly identifies Requirement R2 Part 2.1.3 (Should be Requirement R2 2.1.4). Just to be clear, the developed CAP is to be provided to the applicable RC, BA, AND TOP (all three entities not just one), correct? Technical justifications should be limited to equipment limitations. CAPs could include changes in settings that were not initially recognized as a reliability risk but events have proved otherwise. Should add “(CAPs)” in Requirement R4 first sentence for consistency. Requirement R4 does not set any

timeframes for expected completion of a CAP. An open-ended CAP does not appear to support reliability and the risk associated with IBR performance should be mitigated as quickly as possible. Also, notification of changes in the CAP or completion of the CAP is limited to the RC but should include the BA and TOP. Suggest “Notify the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator if CAP actions or timetables change and when the CAP is completed.” Measure R4 would need the addition of BA and TOP as well. Measure M4 needs to reference “Requirement R4” not “Requirement R3” in the last sentence.

Likes 0	
Dislikes 0	

Response

"R3 requires submitting the CAP and technical justification to the RC. First, the DT expects the GO to consult subject matter experts who will apply sound engineering principles and use good engineering judgement in assessing the plant performance in comparison to the plant's performance requirements. The DT expects accountability to provide a solid technical justification to come from 1) repeated identification for improper performance, 2) review by the RC, and 3) audit for compliance to PRC-030.

The DT updated the Transmission Provider term.

The DT kept the documented process and agrees that it is an important element. The DT also agrees it is important to reinforce the RC may need to request performance reviews as well.

DT changed susceptibility to “applicability of the root cause to” to help clarify the context.

GOs will continue to communicate with the RC/BA/TOP through the currently established processes.

The standard is formatted based on NERC standards.

As the DT understands it, there is no precedent for CAP timeframes. Also, CAPs can be unique and require wide ranging timeframes for resolution. The DT team left establishing a timeline and monitoring the timeline to those entities that would currently be involved with reconciling transmission reliability issues and their current processes."

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	Yes
Document Name	
Comment	
The background information presented in this comment form aligns with the industry need outlined in the SAR.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI appreciates the DT's efforts to set reasonable and workable thresholds for IBR GOs, however, we are concerned that photovoltaic (PV) plants could potentially be over burden administratively given the identified threshold for Real Power output changes of 10% of the plant's nameplate (or 20MW) over a 4 second period. While we understand why the DT chose the 4 second time period, we have no data to validate this is sufficiently narrow to avoid confusing changes in solar irradiance with a plants response to a system disturbance. We further note that for very large PV Plants, this threshold is likely sufficient, but we are concerned that smaller plants could be negatively impacted. To address this concern, we ask that the DT, NERC or one of the technical committees to develop an investigation and written technical justification to support the proposed threshold and or consider consulting with NREL or EPRI to validate the veracity of the proposed threshold.	
Likes 0	
Dislikes 0	
Response	

The DT revised the wording to clarify that the DT intent is 20 MW and 10% change, not 20 MW or 10%. The 20 MW minimum change threshold causes the 10% change to only apply to 200 MW facilities and above. The 4 sec threshold is also meant to provide a significant exclusion because the change must occur quickly, within that time. Based on information available to the DT, wind and irradiance changes do not typically fit that time restraint.	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) does not support the 4 second reporting requirement in the proposed standard draft as that reporting occurrence wouldn't add value and could add unnecessary reporting constraints.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
The MRO NSRF does not believe that the proposed changes in the thresholds are sufficient. Requirement R1, as proposed, focuses on changes in active power output, less a few scenarios, which was not the intention of the SAR.	

Pursuant to the SAR (emphasis added), § Requested Information, ¶2, “IBRs to ensure that any unexpected ceasing of current injection (partial or full) is analyzed by the applicable Generator Owner and mitigated to the extent possible. NERC has also highlighted that many Generator Owners are not aware of these trips and that the Balancing Authority or Reliability Coordinator may often identify the unexpected or unwarranted tripping issues.”

From the excerpt above it is clear that the proposed standard should focus on trips not caused by balance of plant (BOP) Protection Systems, but trips of the individual generating units. As such, the proposed Requirement R1 language needs to focus on generation resource capability, which is based on availability of individual generating units multiplied by the of individual generating unit’s nameplate. For example, consider a wind generation resource with a 100MW aggregate gross nameplate that consists of 50 2MW individual generating units. When the wind generation resource is at 100% availability, then its capability would be 100MW, regardless of fuel supply. If the wind generation resource had 25 individual generating units’ trip in a short period of time (≤ 1 minute), the new capability of the wind generation resource is now 50MW. The intention of the SAR was for Generator Owners to analyze these types of events (individual generating unit trips) to determine if performance issues exist, not any change in active power output.

It is not reasonable or practicable to have Generator Owners analyze every change in active power output even with the exclusions outlined in the proposed requirement. The MRO NSRF strongly encourages the SDT to consider the process that will be required to demonstrate compliance with the proposed Requirement R1 and the amount of administration that will be required to verify whether or not a change in active power meets the criteria for analysis in the Proposed Requirement R1.

The MRO NSRF believe that the that 10% change in the active power output is too low – there are likely to be 10% changes that are not attributed to system disturbances which impact the facility operation. It is suggested that this value be raised back up to 20% range of change.

An MRO NSRF member performed an analysis on one of their IBR facilities (100MW w/ 34 wind turbines) to determine the amount 10% or 20% changes in active power that occur from four-second to four-second or 60 second to 60 second time periods over a six-hour period, the results are as follows.

10% active power change

Total 4s Periods in a 6hr Period = 5400

Total PRC-030 Analysis's Required for a 6hr Period = 2250 or 41.667% (No Requirement R1 exclusions considered)

Please note that there were no 10% capability changes over this six-hour time period.

20% active power change

Total 60s Periods in a 6hr Period = 360

Total PRC-030 Analysis's Required for a 6hr Period = 150 or 41.667% (No Requirement R1 exclusions considered)

Please note that there were no 20% capability changes over this six-hour time period.

An additional concern the MRO NSRF has with the four second time frame is that BAL-005-1 R1 specifies a design scan rate of no more than six seconds for acquiring data necessary for calculating ACE and sending to the BA. That is really the defining time frame that is used to setup EMS systems to query BES RTU data. In addition, other entities could have longer scan rates up to 6 seconds. This is also dependent on the communications path and bandwidth available from EMS to the RTU. If a channel has multiple RTU connections on it, then the scan time can vary as it has to be tuned to be able to respond successfully given the bandwidth available to the multiple RTUs on the channel. The MRO NSRF believes that four seconds may be unachievable for some entities and it seems like the four second time should consider BAL-005-1 and an the amount active power changes that occur at an IBR. The MRO NSRF does not believe that amount of

precision can actually be achieved the way EMS systems are communicating with BA/RCs today unless some other monitoring mechanism is used. As such, the MRO NSRF suggest using a 20% change in capability over a one-minute time period to be the threshold for Requirement R1.	
Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
"The DT considers partial and full power reductions consistent with the SAR. Plants can have partial reductions due to full loss of individual units and plants can have partial reductions by having a proportional reduction across all units. The DT considers both to be partial reductions. The intention of using active power change rather just complete losses is to catch IBR plant performance issue defined in the SAR. The DT did not follow the example well enough to respond. Lengthening the timeframe to 60 seconds will produce more events to review rather than the current four seconds. During normal operations, the longer time windows allow for more change to occur. The standard only wants to identify fast changes. The standard 4 second time only applies to the period of calculating the power change, such as a sudden drop, to be considered valid events not the period of the entire event. A facility can implement the standard by capturing a single drop in telemetry if the scan rate is equal to or greater than four seconds, but a longer period could result in identifying more events than required by the standard. The standard is not intended to apply the four seconds or any scan rate to the entire event (event being the change itself, any pause before restoration, and the restoration of power)."	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	

As previously commented, WEC Energy Group does not agree with the 10% or 20 MVA threshold. The technical rationale states that "was chosen to be large enough to screen out normal operational events but not so large that it does not detect events that should be analyzed". We do not agree that it is large enough to screen out normal events. The "unexpected changes" attributed to weather patterns, change of wind and/or change in irradiance factors occur on a daily basis in some geographical regions, often multiple times per day and can easily drop the site output by 10% or 20MVA. Therefore WEC Energy Group proposes that the threshold should be set to at least 75% of the site nameplate. WEC Energy Group agrees with the MRO NSRF comments/suggestion to merge R1 and R2.	
Likes 0	
Dislikes 0	
Response	
"20 MVA is a common cutoff for other Reliability Standards and the DT used that as a basis for this Standard. In this case, 20 MW is used rather than MVA. Because the 20 MW minimum change threshold causes the 10% change to only apply to 200 MW facilities and above. The 4 sec threshold is also meant to provide a significant exclusion because the change must occur quickly, within that time. Based on information available to the DT, wind and irradiance changes do not typically fit that time restraint. As a preventative measure to allowing smaller magnitude performance issues to persist until they also occur at a time when the power change is larger, the DT believes there is a benefit to reliability by detecting improper operation at lower levels of power change. "	
Douglas Darrah - Clearway Renewable Operation and Maintenance LLC - 5 - MRO,WECC,Texas RE,RF	
Answer	Yes
Document Name	
Comment	
Clearway Renewable Operation and Maintenance LLC ("Clearway") supports the NAGF's comments requesting clarification as to the technical basis for the 4 second event threshold and emphasizing the need to create a standard that optimizes GO staff resources.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment please see the response to MRO NSRF’s 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 the comment please see the response to NAGF’s comment.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
To align with the SAR, the criteria for R1 should include 1.) Any complete facility trip/loss (regardless of the MW output at the time of the event) OR 2.) The ***lower*** of 10% of the plant’s ***gross MW output or input*** or 20 MW if the SDT continues with those thresholds. The 10% threshold may be considered reasonable for the majority of existing IBRs in operation; however future IBRs in the interconnection queue are rapidly growing in size. As of July 1, 2024, 744 new IBR projects in ERCOT will be greater than 200 MW. 85 of those will be greater than 500 MW and 7 of those greater than 1,000 MW. This means that reductions of greater than 100 MW for a 1,000 MW IBR plant could occur that would not be required to be analyzed. If a percentage threshold is still utilized in part of the criteria, it should be replaced with gross active power output (or input for storage). While solar sites may very well be closer to nameplate for several hours	

each day, wind resources are rarely beyond 60%-70% nameplate in ERCOT. Storage IBRs are even less often at nameplate. While ERCOT understands that the RC/BA/TOP may request disturbance data as well, it would be better to improve the criteria for R1 to minimize the need for such requests, allow greater self-monitoring to improve reliability, and minimize conflicts for such requests. ERCOT also recommends clarifying the first sentence to clarify that the active output level must equal or exceed the defined threshold value. Thus, the sentence should be revised to reference “changes in active power output **or input that equal or exceed** the **lower** of 10% of the plant’s gross **MW output or input** or 20 MW.” It is also unclear why the term “Transmission Provider” is being used. The SDT should review the standards or confer with NERC staff on the best functional entity or descriptor for the interconnection transmission provider. Perhaps “Transmission Owner” is the best term.	
Likes 0	
Dislikes 0	
Response	
The DT added a complete loss to R1. The DT also changed the wording of the two limits to 'and' to help clarify that both conditions must be met. The purpose of the two limits is to make the trigger points manageable for both large and small facilities. . The DT agrees that as the plant size grows, so does the trigger threshold, which is why the threshold was reduced from 20% to 10%. However, the DT ran out of time during this review cycle to consider what it thought might be somewhat complex changes to the criteria (the initial thought was to add a third criteria). The DT understands the need from the RC perspective and is one of the reasons the DT included the ability for the RC to request review, even when the 10% threshold is not met.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	

Ameren agrees with most of NAGF's comments, but with one difference. We believe the time period threshold in R1 of PRC-030 should align with PRC-029 if possible or provide a technical basis for choosing 4 seconds. For example, the present draft of PRC-029 dated 2024-03-27 shows a voltage ride-through requirement of 10 seconds for non-wind IBR and 1800 seconds for wind IBR which differs from the 4 second time as used in PRC-030. If the two standards are aligned, clarification should be made in PRC-030 or PRC-029 that if it is discovered that the IBR did not ride-through the expected time, it does not result in a violation of PRC-029 if the PRC-029 study was conducted prior to placing the plant in-service.	
Likes 0	
Dislikes 0	
Response	
The four second is for the initial power change is not related to times in PRC-029. Ride through is about the duration of the event. PRC-030 is triggering off a change over a four second period. PRC-030 only requires detection and evaluation of the event to comply. PRC-029 addresses the ride through performance itself. In that way, the DT believes the two standards are coordinated.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see the response to NPCC's comment.	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company believes that the 10% change in the active power output change is too low. Tthere are likely to be 10% changes that are not attributed to system disturbances which impact the plant operation. Southern Company suggests that this value be raised back up to a 15-20% change. Southern Compay also suggests that footnote 2 be included in the bullet of R1 to eliminate the footnote altogether. In the first sentence of Requirement R1, Southern Company suggests adding "MVA" before "nameplate rating". The intent is not to change any requirement but only to clarify how the required trigger point is determined.	
Likes 0	
Dislikes 0	
Response	
The DT revised the wording to clarify that the DT intent is 20 MW and 10% change, not 20 MW or 10%. The 20 MW minimum change threshold causes the 10% change to only apply to 200 MW facilities and above. Footnote two was moved. The DT understands the value and accuracy of using MVA but believes that will cause inconsistent application or questions about how to reconcile the active power changes with a MVA value.	
Michael Goggin - Grid Strategies LLC - 5	
Answer	Yes
Document Name	
Comment	

We are highly concerned that the updated standard reduced the threshold for output change events that must be reviewed to determine if they need to be analyzed. The revised standard sets the threshold at a change in output that is greater than 10% of the plant's nameplate rating (or 20 MW) within 4 seconds, relative to the previous threshold of 20% within 2 seconds. This change only adds to the generator owner's burden of manually reviewing each output change to exclude events caused by normal fluctuations in plant output due to weather, dispatch, and other factors. No mechanism exists for generator owners to automatically exclude those permissible changes from consideration. Wind and solar plants have a limited number of meteorological towers and pyranometers for measuring the available wind and solar resource, respectively, which makes it difficult in many cases to precisely determine whether changes in output across a plant were caused by resource availability. The new lower threshold will pick up many more such events, as changes of 10% output within 4 seconds routinely occur at solar and wind plants. As we explained in our previous comments, the passage of clouds over small to medium solar plants can cause changes in output of 75% of nameplate capacity per second.[1] As a result, in many cases the vast majority of events a generator owner is required to review will be these normal changes in output, diverting their time and resources away from addressing real reliability concerns. The drafting team's response to our prior comments only reinforces our concern about the burden imposed on the generator owner: "GOs would not know if it was unexpected behavior of generator settings and controls until the analysis is performed. The exceptions that have been moved from the footnote to the Standard Language allow for GOs to dismiss events due to cloud cover, change in wind speed. etc. Outage/Fault codes would be reviewed during the analysis process. It will be up to GOs to develop a process to identify events that that do not fit into the listed exclusions and require further analysis." It is highly burdensome for a generator owner to pull turbine- or inverter-level fault codes and plant-level fault codes for each event with a more than 10% change in output. Moreover, the drafting team cannot ignore the excessive and unworkable burden imposed on generator owners by simply dismissing that with "It will be up to GOs to develop a process to identify events that that do not fit into the listed exclusions and require further analysis." As explained in our answer to question 2 below, the best solution to these concerns may be to remove most if not all of R1, and instead rely on analysis requests initiated by the Reliability Coordinator, Balancing Authority, or Transmission Operator following a disturbance event that causes a drop in generator output per R2. {C}[1]{C} https://www.sciencedirect.com/science/article/abs/pii/S0306261917300144	
Likes 0	
Dislikes 0	

Response	
The DT revised the wording to clarify that the DT intent is 20 MW and 10% change, not 20 MW or 10%. The 20 MW minimum change threshold causes the 10% change to only apply to 200 MW facilities and above. The 4 sec threshold is also meant to provide a significant exclusion because the change must occur quickly, within that time. Based on information available to the DT, wind and irradiance changes do not typically fit that time restraint. The link to the reference document did not provide the full document for review. DT members have reviewed operating data at a few plants and that analysis did not indicate an excessive number of events identified. Clarifying that the DT has always meant 20 MW to be a minimum threshold should reduce the number of potential events. The SAR requires that the GO to be primarily responsible for event detection.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
As drafted, the thresholds in Requirement R1 place a large burden on IBR GOs to analyze events where unexpected changes in active power output occur and events where IBRs respond correctly to System events. We believe this goes against the intent of the SAR, which is "to ensure that any **unexpected** ceasing of current injection (partial or full) is analyzed by the applicable Generator Owner and mitigated to the extent possible." In many cases, irradiance or wind speed data is not captured at such a high resolution from MET stations or it could be limited by data loggers in the field. The thresholds in R1 would result in significant work on the backend to isolate unexpected changes in active power output from changes associated with resource availability or even changes associated with an expected response to a System event. Consider utilizing SCADA scan rates rather than seconds in the threshold criteria.	
Likes 0	
Dislikes 0	
Response	
There is no specific way to define "unexpected" operation, and the use of that term caused considerable discussion about the definition. Rather than define unexpected, the DT noted clear cases of operational events that cause power changes (expected operation). While	

this may highlight the additional variables that impact the review, these variables must still be reviewed, even with a larger percentage, to classify partial reductions as unexpected. Also note that 20 MW for four sec is 5MW/sec or 300 MW/min. As long as the facility ramp rates do not exceed those ramp rates, such as following dispatch commands, then the change in active power would not be expected to meet the R1 criteria. The DT has considered using scan rate but at this time in the process has chosen to stay with the four second time period.	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	
As drafted, the thresholds in Requirement R1 place a large burden on IBR GOs to analyze events where unexpected changes in active power output occur and events where IBRs respond correctly to System events. We believe this goes against the intent of the SAR, which is “to ensure that any **unexpected** ceasing of current injection (partial or full) is analyzed by the applicable Generator Owner and mitigated to the extent possible.” In many cases, irradiance or wind speed data is not captured at such a high resolution from MET stations or it could be limited by data loggers in the field. The thresholds in R1 would result in significant work on the backend to isolate unexpected changes in active power output from changes associated with resource availability or even changes associated with an expected response to a System event. Consider utilizing SCADA scan rates rather than seconds in the threshold criteria.	
Likes 0	
Dislikes 0	
Response	
There is no specific way to define ""unexpected"" operation, and the use of that term caused considerable discussion about the definition. Rather than define unexpected, the DT noted clear cases of operational events that cause power changes (expected operation). While this may highlight the additional variables that impact the review, these variables must still be reviewed, even with a larger percentage, to classify partial reductions as unexpected. Also note that 20 MW for 4 sec is 5MW/sec or 300 MW/min. As long as	

the facility ramp rates do not exceed those ramp rates, such as following dispatch commands, then the change in active power would not be expected to meet the R1 criteria. The DT has considered using scan rate but at this time in the process has chosen to stay with the 4 second time period.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
The percentage of change in active power output identified in R1 should be put back to 20% of the plant's gross nameplate rating as in draft 1 instead of 10%.	
Likes 0	
Dislikes 0	
Response	
The DT team considered making changes and decided to remain at 10%. See other responses for more information.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends clarifying Requirement R1 to state that the GO shall implement a documented process to identify all changes in active power, not just changes in active power output. The Technical Rationale appears to support this its use of the phrase "changes in active power".	

Additionally, Texas RE recommends clarifying Requirement R1 to indicate whether the changes in active power correspond with the duration of the system disturbance. If the intent of the SDT to capture decrease in active power output during any disturbance event regardless of the duration of the disturbance, Texas RE recommends the following revisions. Additionally, Texas RE further asserts that the exemptions in R1 for loss of transmission facilities should apply only to radial facilities and not to locations where multiple transmission lines are terminated at the Point of Interconnection (i.e. loop fed transmission stations or substations). Texas RE's proposed revisions to the language in R1 are provided in bold below: R1. Each applicable Generator Owner shall implement a documented process to identify changes in active power **output** that are the greater of 10% of the plant's gross nameplate rating or 20 MW, and occurring **within during** a **four second** period **that is no longer than 4 seconds**. Changes in active power for the following are excluded: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning] • Changes associated with intermittent primary energy source2 availability; • Resource dispatch, resource ramping, planned outages, or planned resource testing; or • Loss of Transmission Provider's **radial** facilities **to the Point of Interconnection**

Likes 0	
Dislikes 0	

Response
The DT added complete loss to the change specification. DT made changes to R1 considering the Texas RE comments.
Scott Thompson - PNM Resources - 1,3,5 - WECC

Answer	
Document Name	

Comment
Yes, PNM supports the comments of EEI.

Likes 0	
Dislikes 0	

Response

Thank you for comment, please see the DT response to EEI's comment.

2. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

Kim Thomas – Duke Energy	
Answer	Y/N
Document Name	(if an attachment is provided by submitter)
Comment	
Duke Energy requires more information to adequately assess alternatives associated with FERC Order 901.	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
Thank you for the comment.	

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	
Thank you for the comment.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Until Avista owns BPS IBR's generation, the standard has no effect on Avista. If we own IBR generation, we will need digital fault recorders (DFR's) installed to comply with the recording requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
Until we own BPS IBR's generation, the standard has no effect on us. If we own IBR generation, we will need digital fault recorders (DFR's) installed to comply with the recording requirements.	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
Until Avista owns BPS IBR's generation, the standard has no effect on Avista. If we own IBR generation, we will need digital fault recorders (DFR's) installed to comply with the recording requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy offers no alternatives toward the cost effectiveness of these recommendations.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
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	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment.	
Patricia Ireland - DTE Energy - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	
Invenergy is not in a position to comment on the overall cost-effectiveness of the proposed standard as it relates to BES reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
Invenergy is not in a position to comment on the overall cost-effectiveness of the proposed standard as it relates to BES reliability.	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company believes that perhaps determining subsections of the North American electric grid where this detailed monitoring and analysis is most needed rather than requiring it across the entire geographic area is an alternative and more cost-effective option to address the recommendations in the FERC Order. The system stiffness to voltage and frequency fluctuations should be accounted for in regions where the IBR facilities are not likely to be affected by abnormal system condition events. Any possible reduction in the number of facilities required to install this equipment is a direct cost reduction. Souther Company suggests the SDT remove the documented process and just state the GO shall perform a Root Cause Analysis of the performance deviation as there is no need to do all of the documented process steps. Then require the GO shall have documented evidence it performed an RCA on events that qualify.	
Likes 0	
Dislikes 0	
Response	
System strength is not the only indicator of potential for unexpected IBR loss or reductions in active power. Impact of system stiffness on IBR operation varies among IBR plants. Therefore, the DT does not view system strength or other available metrics as valid predictors of system areas with a higher likelihood of IBR performance issues addressed in PRC-030. Need site level monitoring to avoid system-level issues (e.g., coincidental tripping). PRC-030 does not require any specific monitoring methods or equipment. PRC-030 is independent of PRC-028, but it could use data requirements in PRC-028. Documented process is needed to review approach to identifying events to verify parameters are appropriate to capture IBR performance issues applicable under PRC-030.	

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 the comment.	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
The MRO NSRF does not believe that this is cost-effective as currently proposed. Please see the MRO NSRF's other responses to questions. Perhaps determining subsections of the North American electric grid where this detailed monitoring and analysis is most needed rather than requiring it across the entire geographic area. The system stiffness to voltage and frequency fluctuations should be accounted for in regions where the IBR facilities are not likely to be affected by abnormal system condition events. Any possible reduction in the number of facilities required to install this equipment is a direct cost reduction.	
Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Thank you for the comment, this will be passed along to the DT.	

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 Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 2	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power supports MRO’s NERC Standards Review Forum’s (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Tri-State supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
The Standard should be focused on sections of the grid where these disturbances have caused problems. Throwing every conceivable benefit to planners does not ensure that there will be any improvement in reliability. The BAs and the RCs have their work cut out for them and must be or become knowledgeable enough to identify the needs. The real problem is the loss of spinning inertia. There should be a moratorium on retiring generations until solutions are in place and grid stability is restored.	
Likes 0	
Dislikes 0	
Response	
Although some disturbances are reoccurring, past IBR performance issues are not necessarily indicative of future performance issues. System strength is not the only indicator of potential for unexpected IBR loss or reductions in active power. Impact of system stiffness on IBR operation varies among IBR plants. Therefore, the DT does not view system strength or other available metrics as valid predictors of system areas with a higher likelihood of IBR performance issues addressed in PRC-030.	
Alison MacKellar - Constellation - 5	

Answer	Yes
Document Name	
Comment	
Constellation supports NAGF comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation supports NAGF comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	

Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	Yes
Document Name	
Comment	
This standard is essentially an extension of MOD-033 and PRC-002. Modifications of these standards should be made instead of a new standard created since this is not to analyze trip events but to analyze continuous system behavior.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. PRC-002 is associated with the PRC-028 project. The DT does not see link between MOD-033 and PRC-030.	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
SMEs responded with the following “This standard is essentially an extension of MOD-033 and PRC-002. Modifications of these standards should be made instead of a new standard created since this is not to analyze trip events but to analyze continuous system behavior.”	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. PRC-002 is associated with the PRC-028 project. The DT does not see link between MOD-033 and PRC-030.	
Kevin Conway - Western Power Pool - 4	
Answer	Yes

Document Name	
Comment	
Yes, the Drafting team should identify specific performance criterion and require GOs who own IBR resources to meet that performance level. Event Analysis should be completed consistent with Standards like PRC-002, PRC-003 and PRC-004. The key is that the standards must state what the performance measurement is, and then through reporting and auditing compliance would be clearly objective.	
Likes 0	
Dislikes 0	
Response	
PRC-029 outlines the performance criteria and PRC-030 describes monitoring thresholds and subsequent investigative and corrective actions.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	

NV Energy agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Michael Goggin - Grid Strategies LLC - 5	
Answer	
Document Name	
Comment	

To address the concerns we expressed in answer to question 1 above regarding the burden on generators of screening out changes in output that are not caused by disturbances, the best solution may be to remove most if not all of R1, and instead rely on analysis requests initiated by the Reliability Coordinator, Balancing Authority, or Transmission Operator following a disturbance event per R2. This would remove the inefficient “needle in the haystack” burden on generators under R1 to screen every output change event to find the small subset that are due to disturbances, and instead only focus resources on reviewing disturbance events that coincided with a change in output. Because many generators do not have synchrophasors or other equipment required to determine when grid disturbances have occurred, it makes more sense for the analysis to be initiated by a request from the RC, BA, or TO.

We also reiterate our request from the last comment period to add a requirement to R2 that the RC, BA, or TO must file its request within 15 days of the disturbance event. This will ensure that the GO has at least five days to pull data before it is overwritten, given that the data retention period in the current draft of PRC-028 R7 is 20 days.

Finally, the requirement on the generator owner in 2.1.4 for “Determination of the susceptibility of its other inverter-based resource facilities to similar events” appears to be unreasonable if not unworkable. A company that owns multiple IBR plants typically uses different equipment and settings across its plants, and some may be wind plants while others are solar plants, so there is no reason to assume its other plants have the same susceptibility simply because they have the same owner. At minimum, the requirement should be clarified to specify whether non-BES IBR plants owned by the same owner must be assessed as part of compliance with 2.1.4., whether

projects owned by the same parent company but are actually separate LLCs must be assessed as part of compliance with 2.1.4., and other such details.	
Likes 0	
Dislikes 0	
Response	
Regarding applicability of the Standard, the Project 2023-02 SAR states: “The Functional Entities that the proposed standard would apply to are the inverter-based resource Generator Owners. This standard will also give authority to the RC, TOP, or BA to initiate an analysis by a GO if abnormal performance issues are identified.” It could be good practice to request and collect data within a certain number of days to support data availability per PRC-028. However, this does not need to be a requirement in PRC-030. Generator Owner is applied from the NERC registration perspective.	
Scott Thompson - PNM Resources - 1,3,5 - WECC	
Answer	
Document Name	
Comment	
By making EEI's suggested changes to R1, that should lessen the administrative cost associated with the standard. By not capturing everyday and common occurances, operational costs required to remain compliant with the standard should decrease.	
Likes 0	
Dislikes 0	
Response	
R1 has exceptions intended to filter every day, common occurrences and instead focus on unexpected partial of full loss of IBR plant active power output. See response to suggested changes to R1.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	

Document Name	
Comment	
Ameren agrees with NAGF's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Douglas Darrah - Clearway Renewable Operation and Maintenance LLC - 5 - MRO,WECC,Texas RE,RF	
Answer	
Document Name	
Comment	
Clearway will need more information to evaluate the proposed approach.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	
Document Name	
Comment	

N/A	
Likes 0	
Dislikes 0	
Response	
Thanks for the comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI has no suggestions for alternatives in addressing the associated FERC Order 901 directives that are being covered within this project.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
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	
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."

It is imperative that the standard drafting teams for this project as well as the 2021-04 (PRC-002 and PRC-028) and 2020-02 (PRC-029 and PRC-024) assure a coherent way of addressing the inclusion and exclusion of IBRs in current and upcoming standards. These three different projects have all used different ways of drafting up section 4.2 of the standard.

The following comments are specific to PRC-030-1, Requirement R1:

- Add an exclusion for active power changes linked to frequency regulation and power limitations/runback ordered by the TO.
- Add an exclusion for faults inside the IBR plant.

Likes 0	
Dislikes 0	

Response

The IBR definition was approved with an invalid unenforceable term within the term. The IBR term is out for ballot again and will be closing before PRC-030-1 is posted. The PRC-030-1 standard will include the capitalized IBR term in the standard.
The DT added an R1 exclusion for Frequency Response. Power limitations/runback are addressed by the second bullet point exclusion elements related to ramping and dispatch.
Thank you for the suggestion the team will discuss these exclusions and decide if they should be included.

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	
Document Name	

Comment

No comment on cost-effectiveness. WECC leaves that to the applicable entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.	
Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
Thank you for the comment.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost-effectiveness.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment.	

3. Does the entity have any concerns regarding the 2023-02 Implementation Plan? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

Kim Thomas – Duke Energy	
Answer	Yes
Document Name	

Comment	
Duke Energy suggests extending Implementation Plan timeline to 18 months due to budgeting, planning, procurement, installation/implementation, and vendor concerns.	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
Thank you for the comment.	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	
Comment	
FirstEnergy has no objections to the proposed Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	

Not applicable to Avista at this time	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
Not applicable to us at this time since we do not own any IBR generation.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Not applicable to Avista at this time	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
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 Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment. See the Responses to EEI and MRO comments.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI has no objections to the proposed Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
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 have any concerns with the Implementation Plan with acknowledgment of changes needed as noted in the previous questions and in the Additional Comments below.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	

Answer	No
Document Name	
Comment	
NV Energy agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment.	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Thank you for the comment.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Scott Thompson - PNM Resources - 1,3,5 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment.	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2024	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	

Comment	
For many entities the Standard, as proposed, will require more than 6 months to implement and be compliant with. Entities should be given 6 months to create a plan and submit it to the Regional Entity for approval. The plan would include when the entity the anticipated date when all facilities can be brought up to compliance.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the team has extended time frame to 12 months.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Implementing changes to the active power output will require software and possibly hardware modifications or additions. Having only six months to design and implement this modification is not reasonable. Instead, AEP recommends an implementation period of 18 months.	
Likes 0	
Dislikes 0	
Response	
The implementation plan is to develop and implement the process to identify events. Hardware changes are not foreseen as necessary to comply with the Standard.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	

Comment	
Having the “process” mandated by Requirement R1 within 6 months is probably reasonable. However, having the “ability” to implement the process within 6 months, if it doesn’t already exist with the plant, will be nearly impossible. It could require a design change, equipment procurement, and plant modification, which could easily take a year or longer, given current manpower and supply chain issues. Additionally, most utilities would likely have to secure the services of a limited number of contracting companies with the necessary experience to do the work.	
Likes 0	
Dislikes 0	
Response	
Hardware changes are not foreseen as necessary to comply with the Standard.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation supports NAGF comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see the response to NAGF responses.	
Alison MacKellar - Constellation - 5	

Answer	Yes
Document Name	
Comment	
Constellation supports NAGF comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see the response to NAGF responses.	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
The implementation plan should be 365 days instead of 90 days to allow for any control changes that might be required. A process may need to be added to allow extensions of implementation based on potential supply chain issues.	
Likes 0	
Dislikes 0	
Response	
Hardware changes are not foreseen to be required to comply with the Standard.	
Patricia Ireland - DTE Energy - 4	
Answer	Yes

Document Name	
Comment	

The prerequisite section states:

"These standard(s) or definitions must be ***approved*** before the Applicable Standard becomes effective:

- PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
- PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Generating Resources Applicable Entities"

Should be changed to:

"These standard(s) or definitions must be ***implemented*** before the Applicable Standard becomes effective:

- PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
- PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Generating Resources Applicable Entitie"

"These standard(s) or definitions must be ***approved*** before the Applicable Standard becomes effective:

PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Generating Resources Applicable Entitie"

Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the team will consider this change in the next posting.	
Ruchi Shah - AES - AES Corporation - 5	

Answer	Yes
Document Name	
Comment	
AES CE agrees with NAGF's suggestion to extend the proposed Implementation Plan timeline from 6 months to 12 months. This additional time will allow us to explore/configure automation for IBR event identification, event analysis process development/optimization, and corrective action plan development.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see the response to NAGF responses.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation requests the proposed Implementation Plan timeline be changed from 6 months to 12-24 months. This will help generator owner/operators to explore & if purchase - configure automation for IBR event identification, plus event analysis process development and corrective action plans.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see the response to NAGF responses.	

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	
SMUD agrees with the NAGF's suggestion to extend the proposed Implementation Plan timeline from 6 months to 12 months.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see the response to NAGF responses.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF requests the DT to consider extending the proposed Implementation Plan timeline from 6 months to 12 months. This additional time will allow GOs to explore/configure automation for IBR event identification, event analysis process development/optimization, and corrective action plan development.	
Likes 2	JEA, 1, McClung Joseph; Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	

Thank you for the comment, the team has considered and will be making this change in the next posting.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
There is not clarity in the Implementation Plan as it hinges on the Approval of PRC-028 and PRC-029. PRC-028 has a proposed phased in Implementation Plan extending to 2030. While the PRC-028 Standard itself becomes “effective” the Requirements within the Standard are not applicable at the same time which could affect the applicability of inverter-based resources in PRC-029 and PRC-030. WECC suggests the DTs of each Project (PRC-028/029/030) draw a timeline regarding implementation dates so the industry is clear on the expectations. Leaving it to interpretation without clarity in expectations is a detriment for reliability. PRC-030 makes no distinction between existing inverter-based resources and future inverter-based resources but PRC-028 does. Without clarity provided by the DTs, the implementation of these Standards to mitigate the identified risks will not be successful for entities (both from a reliability and compliance perspective.)	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments and support, the team will look into these changes.	
Douglas Darrah - Clearway Renewable Operation and Maintenance LLC - 5 - MRO,WECC,Texas RE,RF	
Answer	Yes
Document Name	
Comment	

Clearway support the NAGF's proposal to extend the Implementation Plan timeline from 6 months to 12 months. As the Generator Owner for over 40 NERC-registered IBRs, Clearway is concerned that the proposed six-month implementation timeline will not give GOs enough time to comply with the proposed standards. Developing the automated monitoring mandated by R1 along with the analysis and reporting procedures required by R2, R3, and R4 will require substantial work to be completed by Clearway's SCADA and engineering teams. A 12-month timeline will meaningfully lessen the compliance burden created by the proposed standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see the response to NAGF responses.	
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 the comment. Please see the response to NAGF responses.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

The Prerequisite section should state that the standards must be approved before “or concurrently with” PRC 028 and 029 to allow for a scenario in which a package of all the standards is submitted to FERC concurrently.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, this is a positive add that the team will consider adding.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with NAGF's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see the response to NAGF responses.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
Considering the amount of data that will need to be filtered, we propose the Implementation Plan be amended to allow entities at least 12 months to implement their process(es) to identify and analyze qualifying events. Alternatively, consider linking the Implementation	

Plan for PRC-030-1 to that of PRC-028-1, given that the required monitoring equipment may be useful in the identification and analysis of qualifying events.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the team has decided to extend the date from six months to twelve months.	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	
Considering the amount of data that will need to be filtered, we propose the Implementation Plan be amended to allow entities at least 12 months to implement their process(es) to identify and analyze qualifying events. Alternatively, consider linking the Implementation Plan for PRC-030-1 to that of PRC-028-1, given that the required monitoring equipment may be useful in the identification and analysis of qualifying events.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the team has decided to extend the date from six months to twelve months.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	

The implementation period should be increased to 2 years to allow for any equipment changes or upgrades needed to comply with the standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the team has decided to extend it to twelve months from six months to fit in with the regulatory mandates.	

4. Provide any additional comments for the Drafting Team to consider, if desired.

Kim Thomas – Duke Energy	
Answer	
Document Name	

Comment
Duke Energy agrees with and recommends implementing the following summarized EEI comments - see EEI submittal for a detailed description of each comment: **EEI COMMENTS** General Comment: Do not agree with the use of non-glossary terms where glossary terms are available and the use of glossary terms that are not capitalized – see EEI submittal for detailed descriptions and potential resolution(s). Applicability Section Comments: Do not agree with the non-industry approved use of Footnote 1 to expand the definition of IBRs and the lack of a technical or SAR justification for the addition of VSC-HVDCs – see EEI submittal for detailed descriptions and potential resolution(s). Requirements Comments: Requirements R2 & R3: Do not agree with the inclusion of requirements that are not clearly defined or sent from multiple registered entities (i.e., RC, BA or TOP) which creates regulatory confusion and undue burden, fails to define compliance responsibility, for functional entity responsibilities not listed in the Applicability section of the Standard – see EEI submittal for detailed descriptions and potential resolution(s). Requirement R4, Subpart 4.3: Suggest adding “Upon Request” to Subpart 4.3 for consistency with Requirement R2, Subpart 2.2 because there should not be a regulatory requirement to notify the RC regarding CAP actions, timetables change and when the CAP is completed, unless the RC specifically requests that the GO provide such notification – see EEI submittal for detailed descriptions and potential resolution(s). Additionally, Duke Energy agrees with and recommends implementing the following summarized NAGF comments - see NAGF submittal for a detailed description of each comment: **NAGF COMMENTS** Provide a technical explanation why in Requirement R2 Part 2.1.3, each applicable Generator Owner shall, within 60 calendar days,

provide a CAP or Technical Justification to the RC, BA, and TOP
Finally, Duke Energy submits the following comment for consideration:

DUKE ENERGY COMMENTS

Standard language consideration should be given to GOs reporting/corresponding to the TP instead of the RC for vertically integrated electric utilities.

Consider substituting the following language for R1 to enhance its clarity: "…identify changes in real power output that are at least 20 MW and greater than 10% of the plant's gross nameplate rating," and occurring during a period that is "within 4 seconds."
Revise Reliability Standard PRC-030-1 June 2024 Technical Rationale Document Figure 1.2: PRC-030-1 Flowchart to read 20 "MW" instead of 20 MVA.

Recommend modifying R1 language to read "…occurring during a period that is "within" 4 seconds." to clarify statement.

Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments

Response

See DT response to EEI and NAGF comments.

RC and TOP are responsible for real time operations and the DT believes communications should be with those entities.

DT has revised language in R1 to clarify MW thresholds and time window.

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	
Document Name	
Comment	

The time periods in R2 and R3 should be increased to 120 calendar days to allow time to determine the root cause and develop a Corrective Action Plan, especially if OEM support is required.	
Likes 0	
Dislikes 0	
Response	
The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2024	
Answer	
Document Name	
Comment	

Regarding R2, Generator Owners should report performance issues more promptly than 90 calendar days. That report only needs to detail the impact of the performance issue then the 90-day assessment would have details and the Generator Owner can complete analysis and develop a corrective action plan in 90 days. Revise R2 wording to:

R2. Each applicable Generator Owner, within 3 business days , shall report the impact of those performance issues to the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator and within 90 calendar days of identifying an active power change event pursuant to Requirement R1 or following a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the inverter-based resource(s) active power output, shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determination of the root cause(s) of change(s) in active power output;

2.1.2. Documentation of the facility’s Ride-through performance including reactive power response during the event;

2.1.3. Assessment of any performance issues identified and if corrective actions are needed; and

2.1.4. Determination of the susceptibility of its other inverter-based resource facilities to similar events.

2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator

R2. If performance issues and corrective actions were identified in Requirement R2 Part

2.1.3, each applicable Generator Owner shall, within 3 business days, report those performance issues to the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator and within 60 calendar days of completing the analysis in Requirement R2, develop one of the following and provide it to the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator. Reports do not have to include details for specific causes but shall provide detail regarding overall impact to the generator facility.

NOTE: MISO is a party to these comments however has opted out of supporting the response to Question 4.

Likes 0	
Dislikes 0	

Response

The DT considered early notification of performance issues and has chosen not add a requirement.

Rhonda Jones - Invenergy LLC - 5

Answer	
Document Name	

Comment

Invenergy thanks the drafting team for the opportunity to provide comments.

Footnote 1: This does not align with the recently approved definition of Inverter-based Resource. If the drafting team intends to include other types of facilities not included in the IBR definition, then those facilities should be separately listed in the Applicability section, rather than as a footnote of BES IBR.

R4.3: This should be removed or amended such that it is only upon request of the Reliability Coordinator.

Likes 0	
Dislikes 0	

Response

The DT has removed footnote 1 from the standard.

The DT kept requirement R4.3 to ensure that the RC is aware of performance issues and when they are corrected.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	

Comment

NV Energy agrees with EEI comments.

Likes 0	
Dislikes 0	

Response

See DT response to EEI comments.

Colin Chilcoat - Invenergy LLC - 6

Answer	

Document Name	
Comment	

Invenergy thanks the drafting team for the opportunity to provide comments.

Footnote 1: This does not align with the recently approved definition of Inverter-based Resource. If the drafting team intends to include other types of facilities not included in the IBR definition, then those facilities should be separately listed in the Applicability section, rather than as a footnote of BES IBR.

R4.3: This should be removed or amended such that it is only upon request of the Reliability Coordinator.

Likes 0	
Dislikes 0	
Response	

The DT has removed footnote 1 from the standard.

The DT kept requirement R4.3 to ensure that the RC is aware of performance issues and when they are corrected.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	
Comment	

Southern Company offers the following comments and questions for the SDT:

- Not seeing relationship of footnote 1 with Facilities 4.2.1.
- Recommend R1 state "… 4 continuous seconds…"
- In R1, delete the word "documented"
- In M1, change"(1) the documented process..." to "(1) implementation of a process for...".
- With the two changes above deleting "documented", item (2) in M1 can be deleted.

• In R2.1.1, be more direct by changing “Determination of the root cause(s)...” to “Determine the root cause(s)..”. • In R2.1.2, be more direct by changing “Documentation of the facility’s...” to “Document the facility’s...”. • R 2.1.2 remove “…including reactive power response during the event.” as it does not align with the purpose statement or R1. This is the only place Reactive Power shows up. • In R2.1.3, be more direct by changing “Assessment of any performance...” to “Assess any performance ...” • In R2.1.3, change the word “needed” to “indicated” to take into account the possibility of there being no changes available to affect the response of the IBR controls to the system disturbance. • R2.1.4 should be removed. Although a good suggestion, in reality this would be difficult to prove and does not show up in the M2. GOs would naturally want to eliminate issues found if they thought they we systemic across multiple locations. • Modify M2 to account for the possible request for results of the analysis by the RC, BA, or TOP by changing “Each applicable Generator Owner shall have dated documentation of the required analysis developed in accordance with...” to “Each applicable Generator Owner shall have dated documentation of the required analysis developed, and the delivery of the analysis when requested, in accordance with...”. • R3 first bullet needs to remove this part of the sentence “…including other applicable facilities owned by the Generator Owner as identified in Requirement R2 Part 2.1.3…” • R3 second bullet needs to remove the word “technical”. There are other reasons that a CAP would not be implemented, such as cost, plant near end of functional life, etc. • Does the BA and TOP also need to appear in the new R4.3 since they appear in the new R3/M3? • Was there a specific reason that the Transmission Planner and/or the Planning Coordinator was not also included in the RC/BA/TOP group each time they appear in the standard? It seems like the Planner may also be interested in the actual performance of the IBR facility. • Purpose needs to read “Identify, analyze, and mitigate unexpected inverter-based resource (IBR) change of Real Power output. Real Power is a NERC glossary term. • Change term “active power” to “Real Power” throughout. • “reactive power”, if used, needs to be capitalized to “Reactive Power” throughout. (Glossary of Terms Used in NERC Reliability Standards)	
Likes 0	
Dislikes 0	
Response	

The DT agreed with many of your comments and made the following changes: -footnote 1 removed -R1 revised -R2 and subsequent sub-bullets revised -updated active power to real power per NERC glossary with appropriate capitalization DT did not add BA and TOP to R4.3 since the RC has ultimate responsibility to system reliability. TP and PC was not included since PRC-030 is an operational standard.

John Pearson - ISO New England, Inc. - 2	
Answer	
Document Name	
Comment	
Under R2, when it is necessary to analyze an event, the GO should notify the applicable Reliability Coordinator, Balancing Authority, or Transmission Operator much more timely than 90 calendar days and a notification should be made the next business day after the event occurred. The notification does not need to include any causal analysis but should provide performance details. The GOs analysis required per R2.1 can be performed within 90 calendar days as described but the RC/BA/TOP should be aware of the potential for such events in the meantime.	
Likes 0	
Dislikes 0	
Response	
The DT considered early notification of performance issues and has chosen not add a requirement.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	

Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
See response to NPCC comments.	
Scott Thompson - PNM Resources - 1,3,5 - WECC	
Answer	
Document Name	
Comment	
PNM supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
See response to EEI comments	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	

Ameren agrees with NAGF's comments.	
Likes 0	
Dislikes 0	
Response	
See response to NAGF comments	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

Regarding R2, Generator Owners should be required to promptly notify the RC/BA/TOP of performance issues before conducting the assessment that is contemplated in this requirement to be completed within 90 days. This would allow the RC/BA/TOP to then initiate its review process and request operational data before any retention periods have expired. The initial notification only needs to provide minimum levels of detail (e.g. date/time, unit, MW impact, any initial assessment). . The wording of R2 can be revised or a separate requirement could be created.

RX.	Each applicable Generator Owner, shall, before the end of the next business day of identifying an active power change event, notify the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator of the event. The notification shall include at a minimum: date, time, unit, change amount, and any initial known causes.

Also, ERCOT recommends modifying R2 to say the following:

R2.	Each applicable Generator Owner, within 90 calendar days of identifying an active power change event pursuant to Requirement R1 or receiving a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a change in the inverter-based resource(s) active power output during or immediately after a Disturbance, shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determination of the root cause(s) of change(s) in active power output;

2.1.2. Documentation of the facility's Ride-through performance including reactive power response during the event;

2.1.3. Assessment of any performance issues identified and if corrective actions are needed; and

2.1.4. Determination of the susceptibility of its other inverter-based resource facilities to similar events.

2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator

R3

For R3, the standard does not provide sufficient clarity about what sorts of technical justifications would justify not implementing corrective actions. For example, would cost be a sufficient ground? As written, the provision for a GO to not be required to implement corrective actions is too broad with no consideration to the reliability impact of not correcting. FERC has recently rejected similarly broad language in the context of NERC-proposed generator weatherization standards. *See* Order Approving Extreme Weather Reliability Standard EOP-012-2 and Directing Modification at p.41, FERC Docket No. RD24-5-000, 21-5-000 (June 27, 2024). Here, as in that case. leaving it up to the generator owner to interpret what it meant to have a technical constraint is unacceptable. The criteria should be "objective, unambiguous, and auditable". *Id.* Moreover, the commission directed in that order that such communications should be confirmed by a reliability entity (e.g. NERC/REs). The need for NERC or RE review should be considered by NERC and the SDT in light of this order, just as the NERC Project 2020-02 SDT is doing for PRC-029.

It is also unclear whether there is any difference between corrective actions “not being applied” and such actions not being “implemented.” The current phrasing seems at best redundant.

ERCOT also believes that CAPs that materially modify the generator’s response characteristics from those based on existing models should be evaluated by the RC/BA/TOP prior to the GO making such changes, and that models should be updated consistent with NERC recommendations in the 2022 Odessa event report. ERCOT does not believe the obligation to update models is adequately captured in the current MOD standards and recommends this be included in a sub requirement to R4 as follows: “Update any dynamic models to reflect the corrective actions if necessary”.

ERCOT also recommends that the Corrective Action Plan should require corrective actions to be implemented within a reasonable timeframe to guard against egregiously long implementation periods.

Finally, ERCOT recommends that the first sentence be clarified to more accurately align with R2’s requirement that the GO must identify only a **need** for a CAP within 90 days. So the opening sentence should read: “If performance issues and **a need for** corrective actions were identified in Requirement R2 Part 2.1.3, ...”

Likes 0	
Dislikes 0	

Response

The DT considered early notification of performance issues and has chosen not add a requirement.

The DT will provide examples of technical justifications in the Technical Rational document.

The DT revised the language for R3 bullet 2.

Revision to the MOD standards addressing generator modeling are forthcoming.

The CAPs include a time table to achieve a solution to address the issue. It is difficult to develop a standard timeline that would be applicable to the wide range of performance issue solutions.

DT made changes to R2.1.3.

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	
See DT comments to NAGF.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
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.	

Likes 0	
Dislikes 0	
Response	
The DT removed footnote 1. The 3 drafting teams of PRC-28, PRC-29, and PRC-30 have aligned applicability.	
Douglas Darrah - Clearway Renewable Operation and Maintenance LLC - 5 - MRO,WECC,Texas RE,RF	
Answer	
Document Name	
Comment	
Clearway supports the additional comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
See comments to NAGF.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
WEC Energy Group agrees with the MRO NSRF about adding exclusions to the applicability section of the proposed standard to ensure that PRC-030 R1 does not include balance of plant (BOP) Protection Systems already covered under PRC-004-6.	

WEC Energy Group supports all NAGF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
See response to MRO NSRF, NAGF, and EEI comments. DT added exclusions for protection system operations in scope for PRC-004	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	MRO-NSRF_2023-02-PRC-030_UCF_04-17-2024_FINAL.docx
Comment	
· §4. Applicability The MRO NSRF reiterates its recommendation that the SDT add exclusions to the applicability section of the proposed standard to ensure that PRC-030 R1 does not include balance of plant (BOP) Protection Systems already covered under PRC-004-6. An example would be PV & wind generation 34.5kV collection system Protection Systems. As the proposed standard is currently drafted there is no clear distinguishing language. It is suggested that the footnote information be included in the §4. Applicability to eliminate the footnote altogether. · Requirement R1: The MRO NSRF would like to reiterate that Requirement R1 “documented process to identify unexpected changes” is not a requirement within the SAR’s scope. According to the SAR, Generator Owners need to “analyze performance issues identified at their facilities”. Having a documented process is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit.	

It is suggested that the footnote information be included in the bullet of R1 to eliminate the footnote altogether.

In R1, suggest the deletion of the word “documented”

In M1, suggest that item 1 be changed from “(1) the documented process...” to “(1) implementation of a process for...”.

With the two changes above deleting “documented”, suggest that item (2) in M1 be deleted.

· Requirement R2:

The MRO NSRF does not agree with allowing the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA) to be able to request an analysis of any a change in “the inverter-based resource(s) active power output”; the criteria for this analysis shall be the same criteria as outlined in Requirement R1.

The MRO NSRF does not agree with the 90 calendar day timeframe and believes it should be 120 days similar to PRC-004-6.

In the new R2, R2.1.1, suggest being more direct by changing “Determination of the root cause(s)...” to “Determine the root cause(s)..”.

In the new R2, R2.1.2, suggest being more direct by changing “Documentation of the facility’s...” to “Document the facility’s...”.

In the new R2, R2.1.3, suggest being more direct by changing “Assessment of any performance...” to “Assess any performance ...”

In the new R2.1.3, suggest changing the word “needed” to “indicated” to take into account the possibility of there being no changes available to affect the response of the IBR controls to the system disturbance.

In the new R2, R2.1.4, suggest being more direct by changing “Determination of the susceptibility...” to “Determine the susceptibility...”.

· Requirement R3:

The MRO NSRF would like to reiterate that being required to provide either a ‘Corrective Action Plan or justification of why corrective actions will not be applied to the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA)’ is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit, if the RC, BA & TOP do not need or want this data & analysis.

· Requirement R4.3:

The MRO NSRF would like to reiterate that the proposed Requirement R4.3 is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit, if the RC, does not need or want this information.

· Requirement R1 & R2

The MRO NSRF would also like to reiterate that most inverter based resources are owned by independent power producers (IPP), as such, it is their best interest to ensure a high availability of the Facility and analyses such as the ones being proposed in PRC-030 are not only in the interest of reliability, but also in the interest of the IPP so long as the criteria for performing an analysis is reasonable and cost effective. The MRO NSRF appreciates the efforts the Standards Drafting Team has put forth and is suggesting the following criteria for the proposed PRC-030 analysis based on the aforementioned information:

Removal of Requirement R1 in its entirety and combining it with the proposed Requirement R2 as follows:

R2. Each applicable Generator Owner, within 120 calendar days of either a, capability1 change of greater than 20% of the generation Facilities gross capability1 nameplate or following a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a capability1 change of greater than 20% of the generation Facilities gross nameplate capability1, shall, excluding:

· Changes associated with intermittent primary energy source (fuel supply: wind, solar irradiance) availability;

· Resource dispatch, resource ramping, planned outages, or planned resource testing; or

· Loss of Transmission Provider’s interconnection facilities.

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in capability1;

2.1.2. Document the Facility's Ride-through performance including reactive power response during the event;

2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the susceptibility of its other inverter-based resource facilities to similar events.

2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator.

1: A generation resource capability is based on availability of individual generating units that compromise the Facility multiplied by the individual generating unit's nameplate.

Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

DT added exclusions for protection system operations in scope for PRC-004

DT decided to leave document process in R1.

DT incorporated footnote 2 into R1.

DT determined that entities responsible for system reliability need an appropriate avenue to trigger evaluation of system events that are not in scope for R1. R1 intended to capture most events but was not able to be designed in a way to capture all events.

The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The 120 day timeframe in PRC-004 was intend to cover wide scale weather events such as hurricanes.

DT accepted wording changes in R2 and sub-bullets.

RC, BA, and TOP have the responsibility for reliability and hence the need to know performance issues associated with such issues.

DT discussed changes of thresholds and decided to keep the 10% nameplate with a 20 MW minimum.

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 – RF	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thanks for the comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

EEI offers the following suggested changes to PRC-030-1:

General Comment: Throughout this Reliability Standard there is use of non-glossary terms where glossary terms are available and should be used. (e.g., active power vs. Real Power) 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.

Applicability Section Comments:

Footnote 1: EEI does not support Footnote 1 because it expands the definition of IBRs beyond what was recently approved by the industry, noting the footnotes expansions the definition of IBR 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 Footnote 1 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 submitted to the industry that defines the issues and risks to BPS reliability that VSC-HVDC systems pose. Lastly, this project has been aligned with FERC Order 901, noting that IBR related performance requirements for ride -through are to be completed and submitted to FERC by Nov. 4th. Yet, the DT expands the definition of IBRs by adding VSC-HVDC systems complicating industry approval without any technical justification for expanding the definition.

Requirements Comments:

Requirements R2 & R3: EEI is concerned with the inclusion of requirements that are not clearly defined or sent from multiple registered entities (i.e., RC, BA 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 actually responsible. (See Requirement R2) 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 R3) We further note that none of the entities identified (i.e., RC, BA, or TOP) are identified within the Applicability section of this proposed Reliability Standard. Yet, all of this places considerable compliance burdens on the IBR-GOs who will need to analyze and resolve (R2) those issues at the request of any of these entities and provide

notification regarding CAP or technical justification, regarding their inability to fully resolve the issues, without any of these entities having clearly defined responsibilities within this standard. **Requirement R4, Subpart 4.3:** EEI suggests adding "Upon Request" to Subpart 4.3 for consistency with Requirement R2, Subpart 2.2 because there should not be a regulatory requirement to notify the RC regarding CAP actions, timetables change and when the CAP is completed, unless the RC specifically requests that the GO provide such notification.	
Likes 0	
Dislikes 0	
Response	
DT has adopted changes to reflect glossary terms. DT removed footnote 1. RC, BA, and TOP have the responsibility for reliability and hence the need-to-know performance issues associated with such issues. RC has the responsibility for reliability and hence the need-to-know performance issues and CAP associated with such issues.	
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	
R2.1- Identifying the root cause of the event and determining the corrective actions required will likely require the IBR manufacturer's collaboration. How can this be done if the manufacturer has gone bankrupt or is unwilling to collaborate. Please indicate what to do for such a situation.	

R2.2 - Why provide the analysis results only if requested. Every analyzed problematic situation report should be transmitted.

R3 - The first bullet, when the CAP identified required modifications to the IBR, should require the OEM to inform all GO using the same technology a CAP is required for their facility.

Likes 0	
Dislikes 0	

Response

GO should seek all reasonable forms of mitigation to fix the problem. To the extent that is not available then it could be a consideration for technical justification.

The DT believes that having the analysis of performance issues provided upon request is a reasonable middle ground between GOs and RC, BA, and TOPs.

Currently, NERC has no jurisdiction over OEMs.

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	
Document Name	

Comment

WECC believes footnote 1 is not cohesive with the phrase to which it is attached and should be removed as it has no bearing or context within this Standard.

Evidence Retention Section needs some adjustments as there are possible differences in the retention requirements for R2 materials. The first bullet indicates saving R2 material for 36 calendar months AFTER completion of the Requirement. The second bullet indicates saving R2 material for “36 calendar months following the completion of each CAP, completion of each evaluation, and completion of each declaration”. WECC suggests the following:

“The Generator Owner shall keep data or evidence of Requirement R1 Measure M1 for 36 calendar months.

The Generator Owner shall keep data or evidence of Requirement R2 Measure M2 and Requirement 3 Measure M3 for 36 calendar months after the development of a Corrective Action Plan.

The Generator Owner shall keep data or evidence of Requirement R4 Measure M4 for 36 calendar months after changes in any Corrective Action Plan actions or timetables or completion."

Severe VSL for R2 needs to capitalize "Ride-through".

VSLs for Requirement R3 need to consistently use "calendar days" as called out within Requirement R3. Consider moving the timeframe to alleviate concerns about "implementation"—Example "The responsible entity failed, within 60 to 90 calendar days, to develop a CAP or provide a technical justification addressing why corrective actions will not be applied nor implemented."

Without any time requirement to complete a CAP and an evidence retention timeframe of 36 calendar months, how would anyone ascertain the CAP was not implemented if the timeframe went past 36 calendar months for completion of activities?

Technical Rationale. At the top of page 2 the sentence "Requirement R3 requires a Corrective Action Plan (CAP) or technical justification when corrective actions are needed" should be adjusted to say "….when, respectively, corrective actions are needed or will not be applied nor implemented". As currently written the latter part of sentence does not appear correct. The Figures should reflect "calendar days" not simply days. Figure 1.2 indicates a change greater than 20 MVA but Requirement R1 language indicates 20 MWs. MVA is a common SCADA-driven point (Facility Ratings are provided in MVA and regularly evaluated by every major EMS vendor for powerflow analysis.)

The exclusions included in Requirement R1 should be in Requirement R1 flow. Consider a decision box under the "10%" that shows "Exclusions in R1" with a flow to "Non-applicable Event". In the Requirement R2 section there should be a Yes path from "Unexpected Performance" to a new box "Performance issues and Corrective Action identified" with a Yes path to R3 and a No path to "No mitigation". Note the rigor of analysis could come into question if an event occurred and the analysis did not identify any corrective actions. Changes to "calendar days" should be made to reflect the Requirement language. "Ride-through" should be hyphenated (page 5 second paragraph.) The Technical Rationale uses the more acceptable language regarding applicability to other units versus the ambiguous "determination of the susceptibility" language within the Standard. Under requirement R3 the sentence "When the IBR Performance issue cause(s) is identified in Requirement R2 or Requirement R3 requires Generator Owner(s) to develop a CAP or provide a technical justification that addresses why corrective actions will not be applied nor implemented" is not a well-developed sentence. Should “or” be removed after “R2”? There is reference to development of multiple CAPs for multiple causes which is valid. However, the analysis must be complete within 90 calendar days and the CAP(s) completed within 60 calendar days of completion of the analysis.

Interconnection requirements historically did not reach the detailed level that analysis of events have revealed. Indicating that older interconnection requirements are a technical justification not to address issues effectively grandfather’s the risk into the ecosystem providing for continued unreliable operations. By doing so, this Standard is not mitigating the risk identified. Additionally, “material modifications” is a term that was written out of FAC-001/002 and should not be used. A technical justification is equipment limitations (not interconnection requirements). Operating limitations should be placed on IBRs not able to meet current interconnection requirements to mitigate the risk posed.

Technical Rationales are to provide reasons why language was provided and not ways to be compliant. The technical justification is more of Implementation Guidance language than a Technical Rationale. While WECC agrees that there may be technical justifications provided, the first example in the Technical Rationale is not technical in nature. If an inverter-based resource could technically not adjust a setting, that would be a technical rationale (and justification).

Likes 0	
Dislikes 0	

Response

Footnote 1 was removed.

DT will look into the retention issues noted.

Thank you for the comments. DT will incorporate these comments as feasible.

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), North American Generator Forum (NAGF), and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 4	
Likes 0	
Dislikes 0	
Response	
See response to EEI, NAGF and MRO NSRF comments.	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	
Document Name	
Comment	
Exelon agrees with the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
See response to EEI comments.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE has the following additional comments: • Requirement R2, subpart 2.2 seems to require that an additional request be made by the RC, BA or TOP for the analysis results. Texas RE recommends the phrase "upon request" be removed from subpart 2.2. Please see the revision below (in bold). 2.2. **Upon request, provide** the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator • Technical Rationale – The Figure 1.2: PRC-030-1 Flowchart should be revised to reflect the 20 MW requirement instead of 20 MVA. • Technical Rationale - On Figure 1.2: PRC-030-1 Flowchart: Texas RE recommends adding a line from Technical Justification box to a new box "Notification to RC, BA, TOP" to match Requirement R3.	
Likes 0	
Dislikes 0	
Response	
The DT took these comments into consideration.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	

Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
See response to MRO NSRF comments.	
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:

Requirement R2:

The NAGF notes that any IBR data request initiated by the Reliability Coordinator (RC), Balancing Authority (BA), and/or the Transmission Operator (TOP) should be contained in its respective data request processes under IRO-010 and TOP-003.

Requirement 2.1.2: The NAGF recommends that this requirement should be included as part of the process created in Requirement R1. In addition, the NAGF is concerned with the potential for overlap with PRC-029.

Requirement R3: The NAGF seeks clarification as to why the Generator Owner must provide a CAP or technical justification to the RC, BA, and TOP.

Requirement R4.3: The NAGF recommends that the DT consider removing the requirement to notify the applicable Reliability Coordinator if CAP actions or timetables change and when the CAP is completed. To the extent the RC wants this information, they should request it under their data specification under IRO-010.

Likes 2	JEA, 1, McClung Joseph; Scott Brame, N/A, Brame Scott
Dislikes 0	

Response

RC, BA, and TOP have the responsibility for reliability and hence the need-to-know performance issues and CAP associated with such issues.

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

Under the Facilities Applicability, Section 4.2.1 states “BES inverter-based resources” and the word “resources” is annotated by Footnote 1. Footnote 1 states “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.”

SMUD believes Footnote 1 is incorrect. Did the Standard Drafting Team (SDT) intend to word Footnote 1 in this manner, or should it be worded similar to Footnote 2 in the latest version of PRC-029-1 which states “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.”

It seems that Footnote 1 in the latest version of PRC-030-1 has been copied in error from PRC-028-1 Draft 3 Footnote 2, which does reference “main power transformers”.

Rather than using the term "BES inverter based resources" and defining "inverter based resources" with a Footnote, SMUD recommends that the PRC-030-1 SDT coordinate with the SDTs for PRC-028-1 and PRC-029-1, and use the glossary term IBR and its definition approved by industry on March 8, 2024 under Project 2020-06. This will ensure accuracy and consistency across all 3 Standard Projects regarding Facilities Applicability and IBRs.	
Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	
DT removed footnote 1. The DT is utilizing the glossary term of IBR.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation agrees with both the NAGF and EEI additional comments for PRC-030-1. Those comments are as follows: NAGF provided the following comments: *For Requirement 2, the NAGF notes that any IBR data request initiated by the Reliability Coordinator (RC), Balancing Authority (BA), and/or the Transmission Operator (TOP) should be contained in its respective data request processes under IRO-010 & TOP-003. Requirement 2.1.2: The NAGF recommends that this requirement should be included as part of the process created in Requirement R1. In addition, the NAGF is concerned with the potential for overlap with PRC-029.* *Requirement R3: The NAGF seeks clarification as to why the Generator Owner must provide a CAP or technical justification to the RC, BA, and TOP.*	

Requirement R4.3: The NAGF recommends that the DT consider removing the requirement to notify the applicable Reliability Coordinator if CAP actions or timetables change and when the CAP is completed. To the extent the RC wants this information, they should request it under their data specification under IRO-010.

EEI - General Comment: Throughout this Reliability Standard there is use of non-glossary terms where glossary terms are available and should be used. (e.g., active power vs. Real Power) 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.

Applicability Section Comments:

Footnote 1: EEI does not support Footnote 1 because it expands the definition of IBRs beyond what was recently approved by the industry, noting the footnotes expansions the definition of IBR 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 Footnote 1 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 submitted to the industry that defines the issues and risks to BPS reliability that VSC-HVDC systems pose. Lastly, this project has been aligned with FERC Order 901, noting that IBR related performance requirements for ride -through are to be completed and submitted to FERC by Nov. 4th. Yet, the DT expands the definition of IBRs by adding VSC-HVDC systems complicating industry approval without any technical justification for expanding the definition.

Requirements Comments:

Requirements R2 & R3: EEI is concerned with the inclusion of requirements that are not clearly defined or sent from multiple registered entities (i.e., RC, BA 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 actually responsible. (See Requirement R2) 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 R3) We further note that none of the entities identified (i.e., RC, BA, or TOP) are identified within the Applicability section of this proposed Reliability Standard. Yet, all of this places considerable compliance burdens on the IBR-GOs who will need to analyze and resolve (R2) those issues at the request of any of these entities and provide notification regarding CAP or technical justification, regarding their inability to fully resolve the issues, without any of these entities having clearly defined responsibilities within this standard.

Requirement R4, Subpart 4.3: EEI suggests adding "Upon Request" to Subpart 4.3 for consistency with Requirement R2, Subpart 2.2 because there should not be a regulatory requirement to notify the RC regarding CAP actions, timetables change and when the CAP is completed, unless the RC specifically requests that the GO provide such notification.

Likes 0	
Dislikes 0	

Response

See response to NAGF and EEI comments.

Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

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

It does not appear that the text of footnote 1 aligns with the body text for the term "inverter-based resources (IBR)". That footnote text should be updated accordingly to match the intended definition. However, creating a new definition for "inverter-based resources" for this standard (and PRC-028 and PRC-029) 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	
DT has revised applicability section to clarify in scope facilities. DT removed footnote 1. DT capture and updated appropriate NERC Glossary Defined terms.	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	
Document Name	
Comment	
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."	

It is imperative that the standard drafting teams for this project as well as the 2021-04 (PRC-002 and PRC-028) and 2020-02 (PRC-029 and PRC-024) assure a coherent way of addressing the inclusion and exclusion of IBRs in current and upcoming standards. These three different projects have all used different ways of drafting up section 4.2 of the standard.

The following comments are specific to PRC-030-1, Requirement R1 :

· Add an exclusion for active power changes linked to frequency regulation and power limitations/runback ordered by the TO.

· Add an exclusion for faults inside the IBR plant.

Likes 0	
Dislikes 0	
Response	
DT has adopted the IBR glossary term. DT incorporated suggested R1 additions to exclusions.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	
Comment	
Some criteria should be added to the RA/BA/TOP request for analysis under R2. AES CE does not believe that an analysis for changes below the thresholds in R1 should be included in the requirement, even if requested by the RA/BA/TOP.	
Likes 0	
Dislikes 0	
Response	

R1 was designed to capture most performance issues however it was not possible to capture all performance issues. R2 is necessary to allow RC, BA, or TOP to initiate investigations for larger system distubances or performance issues that may not meet R1 threholds.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
Tri-State supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
See response to MRO NSRF comments	
Brian Lindsey - Entergy - 1	
Answer	
Document Name	
Comment	
R2. Data quality concern in an event happening in 4 seconds and being able to complete the analysis. Concerns with having to provide the information to multiple entities. R3 and R4: Have a concern with multiple entities requesting information and a single POC would be more efficient. Should be no need to provide CAP to other entities unless explicitly requested.	

The action to create the Corrective Action Plan should 90 days instead of 60 days. Recommend adding language in R3 that states that if all actions are completed during the analysis phase to correct the issue there will be no need for a CAP.	
Likes 0	
Dislikes 0	
Response	
The DT recognizes the GO may have limited data to analyze events until PRC-028 is fully implemented. The GO should use the best available information at the time of the event. RC, BA, and TOP have the responsibility for reliability and hence the need-to-know performance issues and CAPs associated with such issues. DT determined to leave development of the CAP to 60 days. CAP still should be documented.	
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 suggested changes to PRC-030-1: General Comment: Throughout this Reliability Standard there is use of non-glossary terms where glossary terms are available and should be used. (e.g., active power vs. Real Power) 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. **Applicability Section Comments:** Footnote 1: EEI does not support Footnote 1 because it expands the definition of IBRs beyond what was recently approved by the industry, noting the footnotes expansions the definition of IBR 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 Footnote 1 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 submitted to the industry that defines the issues and risks to BPS reliability that VSC-HVDC systems pose. Lastly, this project has been aligned with FERC Order 901, noting that IBR related performance requirements for ride - through are to be completed and submitted to FERC by Nov. 4th. Yet, the DT expands the definition of IBRs by adding VSC-HVDC systems complicating industry approval without any technical justification for expanding the definition.

Requirements Comments:

Requirements R2 & R3: EEI is concerned with the inclusion of requirements that are not clearly defined or sent from 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) 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 R3) 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 places considerable burden on the IBR-GOs that needs to be resolved and clarified.

Requirement R4, Subpart 4.3: EEI suggests adding “Upon Request” to Subpart 4.3 for consistency with Requirement R2, Subpart 2.2 because there should not be a regulatory requirement to notify the RC regarding CAP actions, timetables change and when the CAP is completed, unless the RC specifically requests that the GO provide such notification.

Likes 0	
Dislikes 0	
Response	

See response to EEI comments.
Alison MacKellar - Constellation - 5

Answer	
Document Name	

Comment
Constellation supports NAGF comments. Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response
See response to NAGF comments.
Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment
Constellation supports NAGF comments. Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response	
See response to NAGF comments.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
R3 currently reads "… develop one of the following and provide it to the applicable Reliability Coordinator, Balancing Authority, *and* Transmission Operator." Shouldn't this say "…Reliability Coordinator, Balancing Authority, *or* Transmission Operator"? (Same with M3.) R4.3 should also require notification "to each the applicable Reliability Coordinator, Balancing Authority, or Transmission Operator" rather than only to the Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	
RC, BA, and TOP have the responsibility for reliability and hence the need-to-know performance issues and CAPs associated with such issues. RC has ultimate responsibility for reliability and hence the need to know once the CAP is implemented.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	

FirstEnergy believes that the request for information to and from an IBR Owner may require a full 120 days similar to PRC-004 (understanding IBR's are excluded from PRC-004). We therefore are asking the DT to consider matching the timeframe for PRC-030 with that of PRC-004. This would also provide consistency throughout the industry and eliminate confusion between these two standards.

We also suggest that the third criteria under R1 be changed from “Transmission Provider’s” to “Transmission Service Provider” noting that Transmission Provider is not a defined term in the NERC Glossary.

Likes 0	
Dislikes 0	

Response

The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes.

DT has made changes to R1 exclusion list.

Thomas Foltz - AEP – 5

Answer	
Document Name	

Comment

As AEP stated in the previous ballot period, the scope and general intent of PRC-030 appears reasonable, but the process and flow are flawed and needs to be changed. While it might be reasonable to simply identify the “event” within 90 days (or 120 days to match PRC-004), additional time will still be needed to research and determine the root cause(s). This could conceivably take 90 days or more, especially if support is needed from the OEM. And once the cause is determined, at least 60 additional days (to match PRC-004) would then be needed to develop the CAP and document the Applicability (R2.1.2) of that CAP to other facilities. Applicability cannot be documented without first determining the root cause and then possibly developing the CAP. It cannot be assumed that a root cause will be found in every case, and the standard needs to allow for this. To further illustrate our concern, the standard drafting team provided this response to AEP comments: “The Drafting Team believes it should be up to the GO to develop a process to identify and analyze events. Requirement R2 makes it clear that they have 90 days from the date of the event to complete analysis, regardless of when the event was identified. They also have 90 days to complete analysis of events identified by the BA, RC, or TOP from the date they were notified of the event." AEP understands this response, however the revisions to the standard do not match this response. Specifically, "that they have 90 days from the date of the event" is not what is written in R2. R2 presently reads "within 90 calendar days of identifying an active power change event", which has a different meaning. AEP agrees that it should be measured from the date of the event, not the date of identifying an event. One related gap, as we see it, is that it is not explicitly clear how many days are afforded to identify an event, though 90 days are inferred. These collective concerns are the primary driver behind our decision to vote negative on PRC-030.

The proposed version of PRC-030 makes the assumption that a root cause will be found in every case, but this is not realistic. The standard must be revised to accommodate for situations where a root cause(s) is never found or identified.

AEP would like to see the timelines align with those used in PRC-004, where appropriate.

It might be advantageous for a flowchart to be added to the Technical Rationale document. In that light, AEP reads the present structure for R2/R3 as follows:

After R2 Event identification date or Event Notification date occurs, will within 90 days perform the following:
1) Determine root cause of change in power output
2) Document plant ride-through performance for the event
3) Assessment of any performance issues and if any corrective actions are needed
4) Determine susceptibility of other IBRs to similar events (applicability)
After these are accomplished, then proceed to R3 obligations to develop CAP or make No CAP declaration.

In addition, AEP would prefer the proposed structure for R2/R3 to be as follows:
R2:
1) Event date or Event Notification starts process to complete the following within 120 days of the Event or within 60 days of Event Notification, whichever is later
a) Document plant ride-through performance for the event and
b) Assessment of any performance issues and if any corrective actions are needed
2) R3: Once the Root Cause is found/identified, the following must be accomplished within 60 days:
a) Determine susceptibility of other IBRs to similar events (applicability)

b) Develop CAP or make a No CAP Declaration The new footnote 1 is problematic, as it does not appear to correlate with the IBR. We believe its inclusion may have been unintentional. R2 and R3 include the word “applicable” when referencing the RC, BA, and Transmission Operator, however we believe this word is misleading and may be interpreted inconsistently. As a result, we recommend removing this word from R2 and R3.	
Likes 0	
Dislikes 0	
Response	
The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes. The DT’s intent was that the GO review and identification of R1 events would occur in a timely fashion. The DT decided to align the 90-day analysis period for both self-identified events (R1) and RC, BA, or TOP identified events (R2). If no root cause is found, a GO should work with the RC to explain the details of the performance issues and develop a monitoring plan to capture future events. Figure 1.1 and Figure 1.2 of the TR includes a flowchart illustrating the intended process for PRC-030. The DT discussed changing the time, however had decided to stick with performing an analysis within 90 days of event identification and 60 days for CAP development. The DT removed Footnote 1. The DT believe applicable in the case of R2 and R3 is a necessary qualifier to determine which RC, BA, or TOP is involved.	
Bruce Walkup - Arkansas Electric Cooperative Corporation – 6	
Answer	

Document Name	
Comment	
R2 and R3 should allow for extended time periods for analysis and implementation. The quantity of events triggers R1 will create and require to be looked at is going to be staggering and if an update is required, the time required to implement them in a large-scale plant could be hard to meet.	
Likes 0	
Dislikes 0	
Response	
The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes.	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	
Document Name	
Comment	
SMEs responded with the following “R2 and R3 should allow for extended time periods for analysis and implementation. The quantity of events triggers R1 will create and require to be looked at is going to be staggering and if an update is required, the time required to implement them in a large-scale plant could be hard to meet.”	
Likes 0	
Dislikes 0	
Response	
The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes.	

Kevin Conway - Western Power Pool - 4	
Answer	
Document Name	
Comment	
The Drafting Team has a challenging task of meeting a FERC directive, yet creating a standard that is acceptable to the affected entities. It is in the best interest of the industry to focus on performance metrics, and not administrative compliance for ensuring there are processes and plans. This has the added advantage of allowing each entity to implement the best solutions for their unique needs.	
Likes 0	
Dislikes 0	
Response	
Performance metrics are being developed under PRC-029.	

End of Report

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reminder
Standards Announcement
Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues

Additional Ballots and Non-binding Poll Open through July 10, 2024

Now Available

Additional ballots for **PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Wednesday, July 10, 2024**.

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 Standards Developer, Josh Blume (via email) or at 470-755-0346. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues observer list" in the Description Box.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

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

Formal Comment Period Open through July 10, 2024

Now Available

A 34-day formal comment period for draft two of **PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation**, is open through **8 p.m. Eastern, Wednesday, July 10, 2024**.

The standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

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.

- *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 a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **July 1-10, 2024**.

For 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 470-755-0346. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues observer list" in the Description Box.

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NERC Standards Balloting System

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Comment Forms

View Real-time Comments

Ballot Results

Comment: View Comment Results
Ballot Name: 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Implementation Plan AB 2 OT
Voting Start Date: 7/1/2024 12:01:00 AM
Voting End Date: 7/10/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 227
Total Ballot Pool: 278
Quorum: 81.65
Quorum Established Date: 7/10/2024 4:50:51 PM
Weighted Segment Value: 41.5

Actions

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	76	1	15	0.319	32	0.681	0	19	10
Segment: 2	8	0.5	4	0.4	1	0.1	0	1	2
Segment: 3	60	1	13	0.302	30	0.698	0	9	8
Segment: 4	13	0.7	3	0.3	4	0.4	0	3	3
Segment: 5	70	1	13	0.31	29	0.69	0	9	19
Segment: 6	44	1	8	0.276	21	0.724	0	6	9
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: 10	7	0.6	5	0.5	1	0.1	0	1	0
Totals:	278	5.8	61	2.407	118	3.393	0	48	51

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		None	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
1	Manitoba Hydro	Nazra Gladu		Abstain	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	SaskPower	Wayne Guttormson		None	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
5	Manitoba Hydro	Kristy-Lee Young		Abstain	N/A

6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer	Dane Rogers	Negative	Third-Party Comments
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke		Negative	Third-Party Comments
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Abstain	N/A
6	AEP	Mathew Miller		Negative	Comments Submitted
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
5	American Municipal Power	Amy Ritts		None	N/A
5	Evergy	Jeremy Harris	Hayden	Negative	Comments

			Maples		Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Third-Party Comments
1	Central Iowa Power Cooperative	Kevin Lyons		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras Sr		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted

1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
6	Manitoba Hydro	Brandin Stoesz		Abstain	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Abstain	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	None	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
5	Decatur Energy Center LLC	Megan Melham		None	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		None	N/A
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
6	Western Area Power Administration	Jennifer Neville		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
6	Great River Energy	Brian Meloy		None	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted
5	NextEra Energy	Richard Vendetti		Abstain	N/A
6	Salt River Project	Timothy Singh	Israel Perez	None	N/A

5	Salt River Project	Thomas Johnson	Israel Perez	None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	Constellation	Alison MacKellar		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		None	N/A
1	Ameren - Ameren Services	Tamara Evey		Negative	Comments Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		None	N/A
1	Salt River Project	Laura Somak	Israel Perez	None	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
1	Eversource Energy	Joshua London		Abstain	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Third-Party Comments
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
3	Entergy	James Keele		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Abstain	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
1	Duke Energy	Katherine Street		Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
6	Invenergy LLC	Colin Chilcoat		Negative	Comments Submitted
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
6	Muscatine Power and Water	Nicholas Burns		None	N/A

1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Muscatine Power and Water	Chance Back		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Abstain	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	Invenergy LLC	Rhonda Jones		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Third-Party Comments
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
1	Edison International - Southern California Edison	Robert Blackney		Affirmative	N/A

	Company				
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Comments Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Abstain	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
4	Austin Energy	Tony Hua		Abstain	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Abstain	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		None	N/A
1	Exelon	Daniel Gacek		Abstain	N/A
3	Exelon	Kinte Whitehead		Abstain	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Abstain	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Abstain	N/A

3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		None	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
5	Bonneville Power Administration	Juergen Bermejo		None	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Enel Green Power	Natalie Johnson		None	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Abstain	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	California Department of Water Resources	ASM Mostafa		None	N/A
4	Western Power Pool	Kevin Conway		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		None	N/A
					Third-Party

1	JEA	Joseph McClung		Negative	Comments
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
3	AES - Indianapolis Power and Light Co.	Leo Bernier		None	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
3	JEA	Marilyn Williams		None	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	JEA	John Babik		None	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Third-Party Comments
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Negative	Third-Party Comments
1	Lincoln Electric System	Josh Johnson		Negative	Third-Party Comments
5	Lincoln Electric System	Brittany Millard		Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		None	N/A
3	Lincoln Electric System	Sam Christensen		Negative	Comments Submitted
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Third-Party Comments
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments

1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads	None	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas	Negative	Third-Party Comments
3	Central Electric Power Cooperative (Missouri)	Adam Weber	Negative	Third-Party Comments
5	BC Hydro and Power Authority	Quincy Wang	Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu	None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan	None	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos	Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer	None	N/A

Ballot Results

Ballot Name: 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues PRC-030-1 | Non-binding Poll AB 2 NB
Voting Start Date: 7/1/2024 12:01:00 AM
Voting End Date: 7/10/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 206
Total Ballot Pool: 262
Quorum: 78.63
Quorum Established Date: 7/10/2024 5:25:30 PM
Weighted Segment Value: 24.68

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	73	1	7	0.163	36	0.837	19	11
Segment: 2	7	0.3	2	0.2	1	0.1	2	2
Segment: 3	56	1	8	0.216	29	0.784	10	9
Segment: 4	13	0.7	3	0.3	4	0.4	3	3
Segment: 5	66	1	10	0.286	25	0.714	11	20
Segment: 6	41	1	4	0.167	20	0.833	6	11
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: 10	6	0.5	4	0.4	1	0.1	1	0
Totals:	262	5.5	38	1.731	116	3.769	52	56

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		None	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		None	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer	Dane Rogers	Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A

3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Comments Submitted
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke		Negative	Comments Submitted
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
6	AEP	Mathew Miller		Negative	Comments Submitted
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A

6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Comments Submitted
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Comments Submitted
1	Central Iowa Power Cooperative	Kevin Lyons		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras Sr		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Abstain	N/A

5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Salt River Project	Mathew Weber	Israel Perez	None	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
5	Decatur Energy Center LLC	Megan Melham		None	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		None	N/A
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
6	Western Area Power Administration	Jennifer Neville		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
6	Great River Energy	Brian Meloy		None	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	None	N/A
5	NextEra Energy	Richard Vendetti		Abstain	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	Constellation	Alison MacKellar		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		None	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		None	N/A
1	Salt River Project	Laura Somak	Israel Perez	None	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A

10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
1	Eversource Energy	Joshua London		Abstain	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
3	Entergy	James Keele		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Abstain	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
1	Duke Energy	Katherine Street		Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Comments Submitted
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
5	National Grid USA	Robin Berry		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
6	Muscatine Power and Water	Nicholas Burns		None	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Muscatine Power and Water	Chance Back		Negative	Comments Submitted
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A

1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Negative	Comments Submitted
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Comments Submitted
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Abstain	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted

5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
4	Austin Energy	Tony Hua		Abstain	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Abstain	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
5	Tennessee Valley Authority	Darren Boehm		None	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		None	N/A
1	Exelon	Daniel Gacek		Abstain	N/A
3	Exelon	Kinte Whitehead		Abstain	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Abstain	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Abstain	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		None	N/A
					Comments

3	National Grid USA	Brian Shanahan		Negative	Submitted
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo		None	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Enel Green Power	Natalie Johnson		None	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	Comments Submitted
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Abstain	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	California Department of Water Resources	ASM Mostafa		None	N/A
4	Western Power Pool	Kevin Conway		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		None	N/A
1	JEA	Joseph McClung		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
3	AES - Indianapolis Power and Light Co.	Leo Bernier		None	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Comments Submitted
3	JEA	Marilyn Williams		None	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	JEA	John Babik		None	N/A
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	None	N/A

1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston	Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe	Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry	Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver	None	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson	Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson	Abstain	N/A
5	Lincoln Electric System	Brittany Millard	Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp	None	N/A
3	Lincoln Electric System	Sam Christensen	Abstain	N/A
1	M and A Electric Power Cooperative	William Price	Negative	Comments Submitted
3	M and A Electric Power Cooperative	Gary Dollins	Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth	Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund	Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads	None	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber	Negative	Comments Submitted
5	BC Hydro and Power Authority	Quincy Wang	Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu	None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan	None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer	None	N/A

[redacted]

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-030-1 is posted for a 22-day formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 25, 2023
SAR posted for comment	February 22, 2023 – March 23, 2023
25-day formal comment period with ballot	March 25, 2024 – April 18, 2024
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05-day final ballot	TBD
Board adoption	August 14 - 15, 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:** Unexpected Inverter-Based Resource Event Mitigation

2. **Number:** PRC-030-1

3. **Purpose:** Identify, analyze, and mitigate unexpected Inverter-Based Resource (IBR) change of power output.

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) 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.

5. **Effective Date:** See Implementation Plan for PRC-030-1

B. Requirements and Measures

R1. Each applicable Generator Owner shall implement a documented process 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 4 second period. Changes in Real Power for the following are excluded: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- 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 IBR generator; or
- Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.

M1. Each applicable Generator Owner shall have evidence which includes but is not limited to: (1) the documented process for detecting changes in output as described in Requirement R1, (2) evidence to demonstrate implementation of its documented process, (3) actual data recordings, and (4) identification of gross nameplate rating.

R2. Each applicable Generator Owner, within 90 calendar days of identifying an Real Power change event pursuant to Requirement R1 or following a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the Inverter-Based Resource(s) Real Power output, shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in Real Power output;

2.1.2. Document the facility's Ride-through performance including Reactive Power response during the event;

2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities.

2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator.

M2. Each applicable Generator Owner shall have dated documentation of the required analysis developed in accordance with Requirement R2. Evidence may include, but is not limited to: (1) an analysis report, (2) actual data recordings or derivations, (3) documents describing the device specification and device configuration or settings, and (4) plant configuration.

R3. If performance issues and a need for corrective actions were identified in Requirement R2 Part 2.1.3, each applicable Generator Owner shall, within 60 calendar days of completing the analysis in Requirement R2, develop one of the following and provide it to the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- A Corrective Action Plan (CAP) for the identified inverter-based resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R2 Part 2.1.3; or
- A technical justification that addresses why corrective actions will not be implemented.

M3. Each applicable Generator Owner shall have dated evidence (electronic or hardcopy format) that demonstrates it developed a CAP or a technical justification, and evidence of transmittal to the Reliability Coordinator, Balancing Authority, and Transmission Operator in accordance with Requirement R3.

R4. Each applicable Generator Owner shall, for each of its Corrective Action Plans developed pursuant to Requirement R3: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

4.1. Implement the CAP;

4.2. Update the CAP if actions or timetables change; and

4.3. Notify each applicable Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

M4. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, communication with equipment manufacturers, and communication with each applicable Reliability Coordinator that documents the implementation, updating, or completion of a CAP in accordance with Requirement R3.

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 shall keep data or evidence of Requirement R1, and R2, Measure M1, and M2 for 36 calendar months following the completion of each Requirement.
   - The Generator Owner shall retain evidence of Requirement R3, Measure M3, including any supporting analysis per Requirements R2 and R3, for a minimum of 36 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.
   - The Generator Owner shall retain evidence of Requirement R4, Measure M4 for a minimum of 36 calendar months following completion of each CAP.

   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 responsible entity failed to implement a documented process to identify changes in RealPower output in accordance with Requirement R1.
R2.	The responsible entity performed an analysis in accordance with Requirement R2, but in more than 90 calendar days but less than 120 calendar days of first identifying an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 120 or more calendar days but less than 150 calendar days of first identifying an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 150 or more calendar days but less than 180 calendar days of first identifying an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 or Part 2.1.4. OR The responsible entity failed to provide the analysis results from the requesting entity in accordance with Requirement R2, Part 2.2.	The responsible entity developed an analysis in accordance with Requirement R2, but in 180 calendar days or more of first identifying an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 and Part 2.1.4. OR The responsible entity failed to document the facility's ride-through performance in accordance with Requirement R2, Part 2.1.2 OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The responsible entity failed to determine the susceptibility of other inverter-based resource facilities in accordance with Requirement R2, Part 2.1.3.
R3.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 60 days, but provided it within 90 days.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 90 days, but provided it within 120 days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 120 days, but provided it within 150 days OR The developed CAP did not include corrective actions for other facilities owned by the Generator Owners as identified in Requirement R2 Part 2.1.3, if necessary. OR The developed CAP or technical justification was not provided to the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented, within 150 calendar days.
R4.	The responsible entity implemented, but failed to	N/A	N/A	The responsible entity failed to implement a CAP in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	update a CAP, when actions or timetables changed, in accordance with Requirement R4.			accordance with Requirement R4.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan.

Version History

Version	Date	Action	Change Tracking
Initial Draft	**02/06/2024**	**Draft**	
Second Draft	**06/07/2024**	**Draft**	
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Term(s):

None

A. Introduction

1. **Title:** Unexpected Inverter-Based Resource Event Mitigation
2. **Number:** PRC-030-1
3. **Purpose:** Identify, analyze, and mitigate unexpected ~~inverter-based resource~~Inverter-Based Resource (IBR)

   change of power output.
4. **Applicability:**

   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[1](IBR)~~

   4.2.1. The Elements associated with (1) Bulk Electric System (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.
5. **Effective Date:** See Implementation Plan for PRC-030-1

~~[1] 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.~~

B. Requirements and Measures

R1. Each applicable Generator Owner shall implement a documented process to identify any complete facility loss of output, or changes in ~~active~~ Real Power output that are ~~the greater of~~at least 20 MW and at least 10% of the plant's gross nameplate rating ~~or 20 MW, and~~, occurring ~~during a~~within a 4 second period ~~that is no longer than 4 seconds~~. Changes in ~~active~~ Real Power for the following are excluded: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- Changes associated with intermittent primary energy source~~[2]~~ availability, created by changes such as variation in wind speed and solar irradiance;
- Resource dispatch, resource ramping, planned outages, or planned resource testing; ~~or~~
- ~~Loss of Transmission Provider's interconnection facilities.~~
- A Transmission or collection system loss that, by configuration, disconnects the IBR generator; or
- Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.

M1. Each applicable Generator Owner shall have evidence which includes but is not limited to: (1) the documented process for detecting changes in output as described in Requirement R1, (2) evidence to demonstrate implementation of its documented process, (3) actual data recordings, and (4) identification of gross nameplate rating.

R2. Each applicable Generator Owner, within 90 calendar days of identifying an ~~active~~ Real Power change event pursuant to Requirement R1 or following a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the ~~inverter-based resource(s) active power~~Inverter-Based Resource(s) Real Power output, shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. ~~Determination of~~Determine the root cause(s) of change(s) in ~~active~~ Real Power output;

2.1.2. ~~Documentation of~~Document the facility's Ride-through performance including Reactive Power response during the event;

2.1.3. ~~Assessment of~~Assess any performance issues identified and if corrective actions are needed; and

~~[2] Examples include changes in wind, solar irradiance.~~

2.1.4. ~~Determination of the susceptibility of its other inverter-based resource~~Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities~~ to similar events~~.

2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator.

M2. Each applicable Generator Owner shall have dated documentation of the required analysis developed in accordance with Requirement R2. Evidence may include, but is not limited to: (1) an analysis report, (2) actual data recordings or derivations, (3) documents describing the device specification and device configuration or settings, and (4) plant configuration.

R3. If performance issues and a need for corrective actions were identified in Requirement R2 Part 2.1.3, each applicable Generator Owner shall, within 60 calendar days of completing the analysis in Requirement R2, develop one of the following and provide it to the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- A Corrective Action Plan (CAP) for the identified inverter-based resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R2 Part 2.1.3; or
- A technical justification that addresses why corrective actions will not be ~~applied nor~~ implemented.

M3. Each applicable Generator Owner shall have dated evidence (electronic or hardcopy format) that demonstrates it developed a CAP or a technical justification, and evidence of transmittal to the Reliability Coordinator, Balancing Authority, and Transmission Operator in accordance with Requirement R3.

R4. Each applicable Generator Owner shall, for each of its Corrective Action Plans developed pursuant to Requirement R3: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

4.1. Implement the CAP;

4.2. Update the CAP if actions or timetables change; and

4.3. Notify each applicable Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

M4. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, communication with equipment manufacturers, and communication with each applicable Reliability Coordinator that documents the implementation, updating, or completion of a CAP in accordance with Requirement R3.

C. Compliance

1. **Compliance Monitoring Process**

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

   - The Generator Owner shall keep data or evidence of Requirement R1, and R2, Measure M1, and M2 for 36 calendar months following the completion of each Requirement.
   - The Generator Owner shall retain evidence of Requirement R3, Measure M3, including any supporting analysis per Requirements R2 and R3, for a minimum of 36 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.
   - The Generator Owner shall retain evidence of Requirement R4, Measure M4 for a minimum of 36 calendar months following completion of each CAP.

   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 responsible entity failed to implement a documented process to identify changes in ~~active~~ Real Power output in accordance with Requirement R1.
R2.	The responsible entity performed an analysis in accordance with Requirement R2, but in more than 90 calendar days but less than 120 calendar days of first identifying an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 120 or more calendar days but less than 150 calendar days of first identifying an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 150 or more calendar days but less than 180 calendar days of first identifying an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 or Part 2.1.4. OR The responsible entity failed to provide the analysis results from the requesting entity in accordance with Requirement R2, Part 2.2.	The responsible entity developed an analysis in accordance with Requirement R2, but in 180 calendar days or more of first identifying an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 and Part 2.1.4. OR The responsible entity failed to document the facility's ride-through performance in accordance with Requirement R2, Part 2.1.2 OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The responsible entity failed to determine the susceptibility of other inverter-based resource facilities in accordance with Requirement R2, Part 2.1.3.
R3.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 60 days, but provided it within 90 days.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 90 days, but provided it within 120 days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 120 days, but provided it within 150 days OR The developed CAP did not include corrective actions for other facilities owned by the Generator Owners as identified in Requirement R2 Part 2.1.3, if necessary. OR The developed CAP or technical justification was not provided to the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented, within 150 calendar days.
R4.	The responsible entity implemented, but failed to	N/A	N/A	The responsible entity failed to implement a CAP in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	update a CAP, when actions or timetables changed, in accordance with Requirement R4.			accordance with Requirement R4.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan.

Version History

Version	Date	Action	Change Tracking
Initial Draft	**02/06/2024**	**Draft**	
Second Draft	**06/07/2024**	**Draft**	
Third Draft	**07/22/2024**	**Draft**	

Implementation Plan

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1

Applicable Standard(s)

- PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation

Requested Retirement(s)

- None

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Generating Resources

Applicable Entities

- Generator Owner (GO)

Background

Multiple NERC disturbance reports,[1] including the Odessa disturbance report,[2] identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults and have elaborated on the systemic and significant BPS reliability risks that this undesired performance can pose. IBRs may trip for many different reasons, may cease current injection due to inverter controls, or may have unwanted plant-level controller interactions. These types of issues have been extensively documented in the NERC reports. The resulting unexpected and unwarranted loss of generation poses a significant risk to BPS reliability. Project 2023-02 was initiated to address the reliability-related need and benefit by requiring analysis and mitigation of unexpected or unwarranted protection and control operations from inverter-based resources following the identification of such a performance issue.

[1] https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx
[2] https://www.nerc.com/pa/rrm/ea/Pages/May-June-2021-Odessa-Disturbance.aspx

After Project 2023-02 was initiated, FERC issued Order No. 901,[3] which directs the development of new or modified reliability standards, including 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[4]. Within the work plan, NERC identified three active Standards Development Projects that would need to be filed for regulatory approval with FERC November 4, 2024. These projects include 2020-02 Modifications to PRC-024 (Generation Ride Through),[5] 2021-04 Modifications to PRC-002-2,[6] and 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues.[7]

General Considerations

This implementation plan recognizes the urgent need for Reliability Standards to address IBR Corrective Action Plans (CAP) to reduce disturbances, as demonstrated by multiple event reports of the last decade, while providing a reasonable period 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 do not have a standard that addresses CAPs for IBR generation. 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 provides staggered timeframes by which entities shall first ensure the entity has the necessary PRC Reliability Standards, PRC-029-1, in place (12 months following regulatory approval). Subsequent compliance with the “operation” elements of these requirements shall become due as entities follow Ride-Through criteria on each applicable IBR in accordance with the implementation plan for proposed Reliability Standard PRC-029-1 – Frequency and Voltage Ride-Through Requirements for Inverter-Based Generating 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

[3] *Reliability Standards to Address Inverter-Based Resources,* Order No.901, 185 FERC ¶ 61,042 (2023); https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false

[4] *See Informational Filing of the N. Am. Elec. Reliability Corp. Regarding the Development of Reliability Standards Responsive to Order No. 901.*, Docket No. RM22-12-000 (January 18, 2024).

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

[6] *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

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

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-030-1'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

The effective date for the proposed Reliability Standard is provided below.

Standard PRC-030-1

Where approval by an applicable governmental authority is required, Reliability Standard PRC-030-1 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 the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard PRC-030-1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

PRC-030-1 Phased-in Compliance Dates

Requirements R1, R2, R3, and R4

Capability-Based Elements

Bulk-Electric System IBRs

Entities shall comply with the portion of Requirements R1, R2, R3 and R4 relating to the **design** of their BES IBRs to meet the requirements by the effective date of the standard.

Applicable Non-BES IBRs[8]

Entities shall not be required to comply with Requirements R1, R2, R3, and R4 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.

[8] 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."

Performance-Based Elements (all applicable IBRs)

Entities shall not be required to comply with the portion of Requirements R1, R2, R3, and R4 relating to the **operation** of IBRs to meet the requirements until the entity has established the required Ride-through capabilities for those IBRs in accordance with the implementation plan for Reliability Standard PRC-029-1.

Implementation Plan

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1

Applicable Standard(s)

- PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation

Requested Retirement(s)

- None

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

~~PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources~~

- PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Generating Resources

Applicable Entities

- Generator Owner (GO)

Background

Multiple NERC disturbance reports,[1] including the Odessa disturbance report,[2] identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults~~,~~ and have elaborated on the systemic and significant BPS reliability risks that this undesired performance can pose. IBRs may trip for many different reasons, may cease current injection due to inverter controls, or may have unwanted plant-level controller interactions. These types of issues have been extensively documented in the NERC reports. The resulting unexpected and unwarranted loss of generation poses a significant risk to BPS reliability. Project 2023-02 was initiated to address the reliability-related need and benefit by requiring analysis and mitigation of unexpected or unwarranted protection and control operations from inverter-based resources following the identification of such a performance issue.

[1] https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx
[2] https://www.nerc.com/pa/rrm/ea/Pages/May-June-2021-Odessa-Disturbance.aspx

After Project 2023-02 was initiated, FERC issued Order No. 901,[3] which directs the development of new or modified reliability standards, including 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[4]. Within the work plan, NERC identified three active Standards Development Projects that would need to be filed for regulatory approval with FERC November 4, 2024. These projects include 2020-02 Modifications to PRC-024 (Generation Ride Through),[5] 2021-04 Modifications to PRC-002-2,[6] and 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues.[7]

General Considerations

~~The requested implementation timeline allows for ample time for entities to draft and implement their process. The information required for standard compliance is currently available to Generator Owners.~~

This implementation plan recognizes the urgent need for Reliability Standards to address IBR Corrective Action Plans (CAP) to reduce disturbances, as demonstrated by multiple event reports of the last decade, while providing a reasonable period 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 do not have a standard that addresses CAPs for IBR generation. 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 provides staggered timeframes by which entities shall first ensure the entity has the necessary PRC Reliability Standards, PRC-029-1, in place (12 months following regulatory approval). Subsequent compliance with the “operation” elements of these requirements shall become due as entities follow Ride-Through criteria on each applicable IBR in accordance with the implementation plan for proposed Reliability Standard PRC-029-1 – Frequency and Voltage Ride-Through Requirements for Inverter-Based Generating Resources.

[3] *Reliability Standards to Address Inverter-Based Resources,* Order No.901, 185 FERC ¶ 61,042 (2023); https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false
[4] *See Informational Filing of the N. Am. Elec. Reliability Corp. Regarding the Development of Reliability Standards Responsive to Order No. 901.*, Docket No. RM22-12-000 (January 18, 2024).
[5] *See* NERC Standards Development Project page for Project 2002-02; https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx
[6] *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
[7] *See* NERC Standards Development Project page for Project 2023-02; https://www.nerc.com/pa/Stand/Pages/Project-2023-02-Performance-of-IBRs.aspx

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-030-1'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

The effective date for the proposed Reliability Standard is provided below.

Standard PRC-030-1

Where approval by an applicable governmental authority is required, Reliability Standard PRC-030-1 shall become effective on the first day of the first calendar quarter that is ~~six~~12 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, Reliability Standard PRC-030-1 shall become effective on the first day of the first calendar quarter that is ~~six~~12 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

PRC-030-1 Phased-in Compliance Dates

Requirements R1, R2, R3, and R4

Capability-Based Elements

Bulk-Electric System IBRs

Entities shall comply with the portion of Requirements R1, R2, R3 and R4 relating to the **design** of their BES IBRs to meet the requirements by the effective date of the standard.

Applicable Non-BES IBRs[8]

[8] 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."

Entities shall not be required to comply with Requirements R1, R2, R3, and R4 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, R3, and R4 relating to the **operation** of IBRs to meet the requirements until the entity has established the required Ride-through capabilities for those IBRs in accordance with the implementation plan for Reliability Standard PRC-029-1.

Technical Rationale

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1 | July 2024

PRC-030-1 – Unexpected Inverter-Based Resource Event Mitigation

Rationale for Applicability Section

The functional entity responsible for identifying, analyzing, and mitigating unexpected Inverter Based Resources (IBR) performance is the Generator Owner (GO). The Generator Operator (GOP) is not included because of the accountability and coordination issues introduced by listing both GO and GOP as responsible functional entities. Further, this standard intentionally did not include requirements for the Balancing Authority (BA), Reliability Coordinator (RC), and Transmission Operator (TOP) because other standards (e.g., EOP-004) place requirements on these entities for system level events.

General rationale

Aligned with the Project 2023-02 Standards Authorization Request (SAR), the Requirements are structured to identify, analyze, and mitigate IBR performance issues. The SAR discusses how a series of NERC disturbance reports have "identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that these pose". [1,2,3,4,5,6,7,8,9] In particular, IBR performance during events has included tripping or momentary cessation that is unexpected, unwarranted, and poses reliability challenges.

Requirement R1 defines how events are to be identified, along with exceptions that should not be identified. Requirement R2 requires analysis of identified events, with specific elements assessed as

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[1] *Odessa Disturbance,* NERC. September 2021.https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf

[2] *2022 Odessa Disturbance,* NERC. Atlanta, GA: December 2022. https://www.nerc.com/comm/RSTC_Reliability_Guidelines/NERC_2022_Odessa_Disturbance_Report%20%281%29.pdf

[3] *900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*, NERC. Atlanta, GA: February 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

[4] *April and May 2018 Fault Induced Solar Photovoltaic Resource Interruption Disturbances Report*, NERC. Atlanta, GA: January 2019. https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf

[5] *Panhandle Wind Disturbance*, NERC. Atlanta, GA: August 2022. https://www.nerc.com/pa/rrm/ea/Documents/Panhandle_Wind_Disturbance_Report.pdf

[6] *Panhandle Wind Disturbance*, NERC. Atlanta, GA: August 2022. https://www.nerc.com/pa/rrm/ea/Documents/Panhandle_Wind_Disturbance_Report.pdf

[7] *1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*, NERC. 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

[8] *San Fernando Disturbance*, NERC. November 2020. https://www.nerc.com/pa/rrm/ea/Documents/San_Fernando_Disturbance_Report.pdf

[9] https://www.iec.ch/conformity-assessment/what-conformity-assessment

described in subparts. Requirement R3 requires a Corrective Action Plan (CAP) or technical justification when corrective actions are needed. Finally, R4 requires mitigation of the performance risk through CAP implementation. The flow of these requirements is summarized in Figure 1.

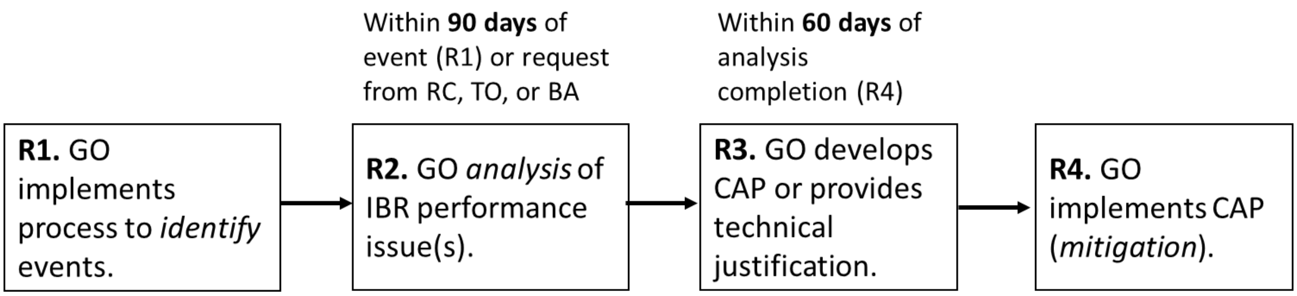

Figure 1.1: Relationship of Requirements in PRC-030-1

The Requirement R1 contains thresholds for identifying events with sudden changes in active power. Figure 1.2 depicts the threshold criteria and logic used in Requirement R1, along with additional details of process flow in Requirement R2.

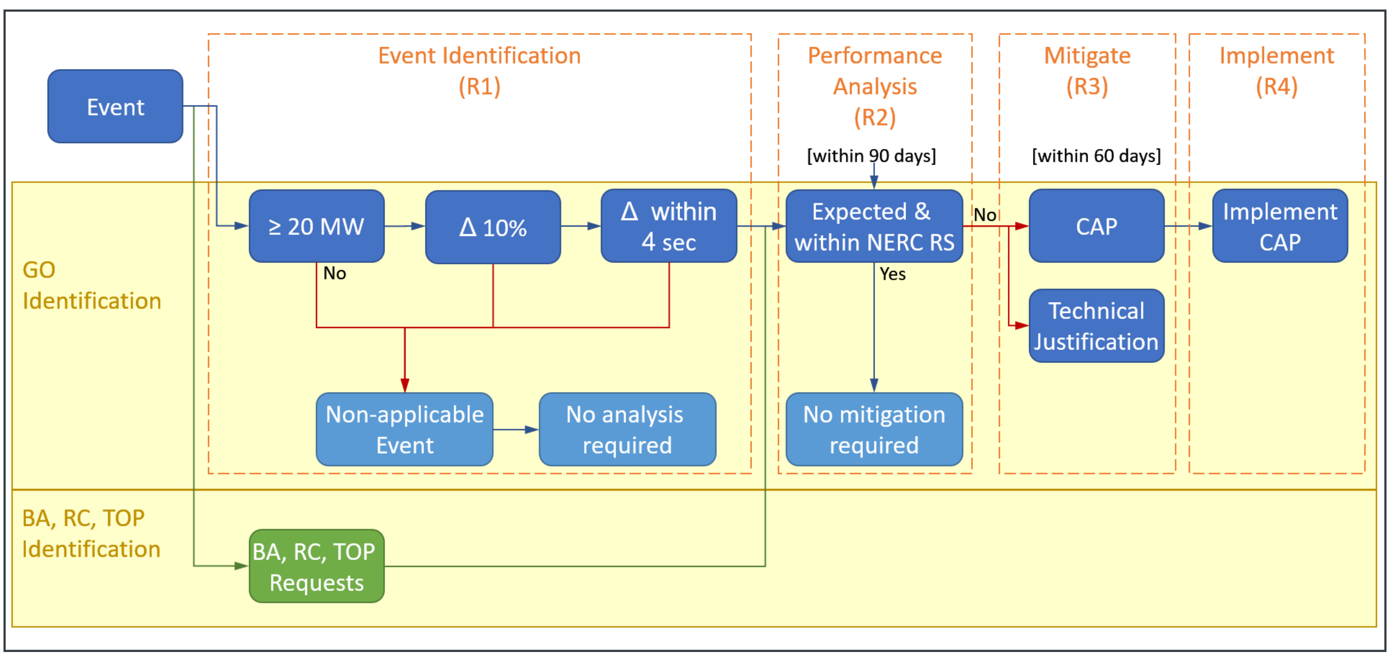

Figure 1.2: PRC-030-1 Flowchart

Rationale for Requirement R1

The intent of Requirement R1 is for the Generator Owner (GO) to implement a documented process to self-identify events that are sufficiently large to warrant an analysis of IBR performance for the identified event. For that reason, the team included the 20 MW minimum threshold, which is a common cutoff for other Reliability Standards, to reduce the number of potential events.

While the GO should consider both active and reactive power responses when an analysis is required, only active power is used as a threshold to trigger analysis. Active power was selected as the monitored parameter to make feasible implementation across IBR plant designs and backend software system (e.g., SCADA).

The thresholds for event identification in R1 effectively provide a two-tier approach depending on the size of the IBR facility. The table below shows the two tiers and the thresholds that should be used to identify events. In addition, all unexpected events in which there is a complete loss of MW output, or active drops to 0 MW, should be identified regardless of plant size and output. This of course excludes planned ramp downs and all other exclusions listed in R1 (solar end of day ramp down, planned outages, loss of connecting transmission facilities, Misoperations identified in PRC-004, etc.).

Facility Nameplate Rating	**Threshold**
200 MW or less	20 MW
Greater than 200 MW	10% of Nameplate Rating (e.g. 30 MW for 300 MW Facility)

Nameplate rating was used as the basis of the change (power or amperes) because it is the common reference in NERC and other industry standards. The IBR continuous rating concept outlined in IEEE 2800-2022 definitions was considered and determined to be a departure from NERC standards approaches to date.

The 10% of nameplate rating for magnitude of event threshold was chosen to be large enough to screen out small active power changes but low enough to detect events that should be analyzed for reliability purposes. The percent change is intended to address facilities with greater than 200 MW nameplate rating where 10% is a significant change, otherwise the 20 MW threshold sets a minimum threshold for event identification. The 20 MW minimum change threshold causes the 10% change to only apply to 200 MW facilities and above.
For smaller capacity facilities, the use of only a percent change as the screening criteria would lead to identification of disturbances that are not likely to be significant for analysis.

To restate the criteria another way:

- For plants with 0 – 200 MW gross nameplate rating, the change must be at least 20 MW,
- For plants 200 MW gross nameplate rating and larger, the change must be at least 10% of the gross nameplate rating

The criteria could be charted as depicted below.

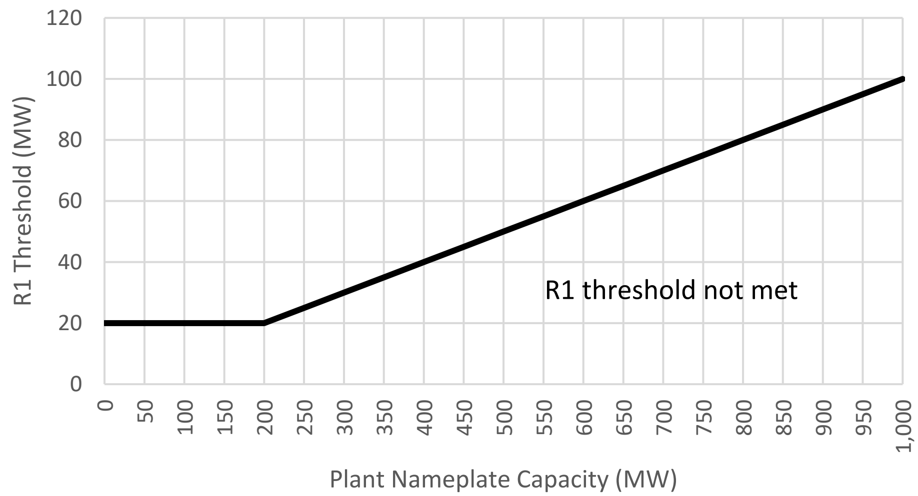

Figure 1.3: R1 MW Threshold Versus Plant Capacity

The purpose of the two limits is to make the trigger points manageable for both large and small facilities. The DT recognizes that as the plant size grows, so does the trigger threshold, that is why the threshold was set at 10% rather than something larger, like 20%. While the GO would not be required to identify events below the 10% threshold for large plants, the RC is explicitly given the option to request a review in the requirement.

The DT revised the wording of R1 to clarify that the DT intent is 20 MW and 10% change, not 20 MW or 10%. While the DT considered the existing criteria sufficient, a complete loss of the facility was also included as an R1 condition.

At one point, the DT considered using the terms sudden and unexpected, but that led to much uncertainty and discussion as to how that would be applied consistently. Therefore, the DT chose to bound the initial change at event onset to a four second timeframe.

The various SCADA scan rates in use at ISOs/RTOs as well as NERC standard minimum required scan rates were considered in selecting four seconds. SCADA monitoring is a likely method for monitoring active power changes. Power changes that occur and recover within one scan are not expected to be detected by the Requirement R1 process implemented by GOs. The four seconds was not intended to define the scan period, but only to characterize the change as sudden when considering information on monitoring capabilities across the industry. If a facility is using a scan rate of four seconds or greater to monitor active power output, the GO should use the change in active power output in one scan rate to identify events meeting R1 criteria. It should be noted that using longer time periods or scan rate could lead to a need for more sophisticated event screening or may otherwise lead to identification of more invalid events that occur on slower timescales.

The intention of the four seconds was to limit the time within which the change is calculated. The DT also considered that units following normal operation dispatch commands tend to move more slowly. Using the 20 MW for foursec, the change rate is 5MW/sec or 300 MW/min. Lower ramp rates would not be expected to meet the R1 criteria.

The following set of charts, in Figure 1.4, are examples of expected event scenarios and whether they meet the R1 criteria.

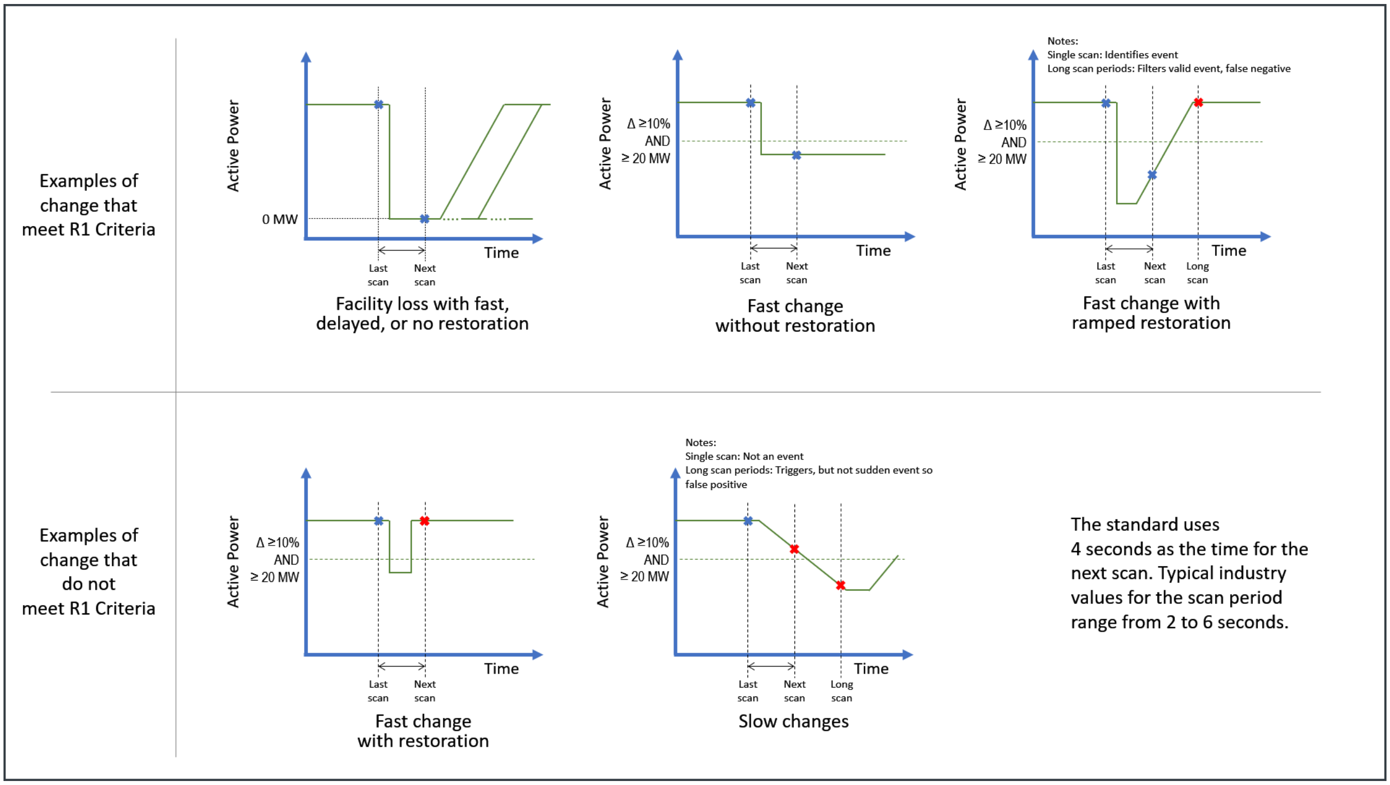

Figure 1.4: PRC-030-1 Flowchart

Due to concern voiced by industry that the thresholds defined in R1 could be often exceeded during the normal operation of an IBR facility, the DT examined three IBR facilities in Texas to determine the frequency of such events.

Solar facility in West Texas with 160 MW nameplate rating:
The DT analyzed one year of data encompassing all of 2023 and found five instances in which the facility changed 20 MW or more within a four second period. All five instances were related to ride-through performance issues previously identified by the RC. There were zero events in which active power changed 20 MW or more within four second period due to change of irradiance, ramping due to dispatch, or other reasons listed as exclusions in the R1 bullet list.

Wind facility in Texas Panhandle with 300 MW nameplate rating:

The DT analyzed one year of data encompassing all of 2023 and found zero real events in which the facility changed 30 MW or more within a 4 second period. There were several events that were triggered due to drop outs of telemetry from the facility, but telemetry from the POI verified that there were no actual drops in active power from the facility at the time.

Solar Facility in Central Texas with 500 MW nameplate rating:
The DT analyzed one month of data for June 2024 and found seven events in which the facility changed 50 MW or more within a four second period. This facility appears to have curtailment issues and is not following proper ramp rates during curtailment. The plant was either being curtailed or was released from curtailment at the time which four of the seven events were detected. One of those events showed a large increase of irradiance at the time, but it is unclear if the change of irradiance alone caused the sudden increase in generation or if it was due to improper curtailment ramp rates, or a combination of the two. Two of the other events were related to large oscillations lasting up to an hour in which peak to peak magnitude of the oscillation exceeded 50 MW. The last event was due to a Power Plant Controller issue that caused a sudden drop in active power of 246 MW and was previously identified by the RC. Under R1 requirements, three of the seven events would meet criteria and need to be analyzed in R2. The table below summarizes the results:

Date/Time	Four second MW change	Increase/ Decrease	Significant Irradiance Change	Cause	Should be Analyzed in R2
6/4/2024 1:25:00 PM	83	Increase	Yes	Curtailment issue/ Irradiance change?	No (Resource dispatch and/or change in irradiance exclusion)
6/4/2024 5:00:00 PM	192	Increase	No	Curtailment released	No (Resource dispatch exclusion)
6/14/2024 8:02:00 AM	57	Increase	No	Curtailment issue	No (Resource dispatch exclusion)
6/14/2024 11:36:00 AM	138	Increase	No	Curtailment issue	No (Resource dispatch exclusion)
6/17/2024 11:45:00 AM	246	Decrease	No	Plant controller issue	Yes
6/23/2024 12:30:00 PM	50	Both	No	Oscillation Event	Yes (peak to peak magnitude >50 MW observed)
6/26/2024 4:00:00 PM	78	Both	No	Oscillation Event	Yes (peak to peak magnitude >50 MW observed)

The DT also analyzed data covering one month from four facilities in Hawaii, and found only one event that exceeded thresholds in R1. Since facilities in this area are generally smaller, all four facilities analyzed were less than 200 MW in nameplate rating, so a 20 MW threshold was used for analysis. The DT also looked at an extended time period of 60 seconds, and as expected, more events were identified with the extended time period.

Plant #	1	2	3	4
Technology	Wind	PV	PV/BESS (AC Couple)	BESS Standalone
Facility Nameplate Rating (MW)	69	46	39	135
# of event (4 second, >20 MW)	0	0	0	1 (cause unknown)
# of event (60 second, >20 MW)	0	0	0	8

Due to the above analysis, the DT believes the thresholds in R1 would rarely trigger events due to normal operation of an IBR facility if the facility is operating as expected. The DT only found one possible instance of a facility exceeding the thresholds due to change of irradiance and wind speed, and it is likely one of those events was caused by improper curtailment ramp rates programmed into the PPC. In addition, the DT reviewed papers published by NREL on Solar PV Variability at Small Timescales and Variability of Wind Power Output, which concludes that change in irradiance and wind speed would not have large impacts to changes in output within a narrow timeframe such as a four second period.

The intention of the four second period was to define a sudden change in power, similar to the types of active power loss events described in NERC Disturbance Event reports. The DT considered using the term “scan period” to define the change period, because this scan period is the basis of the time, but chose to stay with the four second time specification. The four second threshold is meant to provide a significant exclusion because the change must occur quickly, within that time. Increasing the time effectively reduces the rate of change and would identify more events than a four second window. The intent is to exclude from review slow power changes expected with normal operations (e.g., variable output from weather, dispatch, planned outages, testing) or expected responses (e.g., loss of interconnection facilities), which were defined as bullet points to Requirement R1.

The standard four second time only applies to the period of calculating the power change, such as a sudden drop, to be considered valid events. This time qualifies what is a sudden or fast change but does not limit or imply any duration for the entire event. While the change must occur within the four second timeframe, the plant response may take ten’s of seconds or even minutes. The standard does specify and limit that time period.

If the facility output changes and then returns to pre-event levels within 4 seconds (dip and return), then the DT recognizes that would not be an event identified by the criteria. Similarly, because of the randomness of events and data sampling, it is possible that a change of less than four seconds can be identified, but those events technically do not meet the criteria.

The term "changes in active power" encompasses both sudden decreases (i.e., loss of output) and increases (i.e., additional consumption) that may be caused by IBR mis-operations that could affect system reliability. For instance, a battery energy storage system that mis-measures system frequency may unexpectedly enter a charging mode and suddenly increase active power draw.

Photovoltaic (PV) example 1 – qualifying:
PV facility with gross nameplate rating of 220 MW is operating with active output of 80 MW. During a transmission system fault event,[10] the plant exhibits a near instantaneous active power output drop to 50 MW.

The change in apparent power in under four seconds is 30 MW, which exceeds 22 MW, the greater of 10% of the plant's gross nameplate (22 MW) or 20 MW. This IBR performance event is required to be captured by the GO's process implemented in Requirement R1.

PV example 2 – non-qualifying:
PV facility with gross nameplate rating of 80 MW is operating with active output of 60 MW. During a transmission line fault event,[1] the plant exhibits a near instantaneous active power output drop to 42 MW.

The change in apparent power in under four seconds is 18 MW, not exceeding 20 MW, the greater of 10% of the plant's gross nameplate rating (8 MW) or 20 MW. This IBR performance event is not required to be captured by the GO's Requirement R1 process.

Battery Energy Storage System (BESS) example 1 – qualifying:
BESS facility with gross nameplate power output rating of 80 MW is operating as a load drawing 50 MW. During a power plant controller ("PPC") malfunction event of the BESS facility, the PPC incorrectly estimates system frequency sending an incorrect frequency response signal causing the plant to exhibit a near instantaneous change in real power to 10 MW injection.

The change in apparent power in under four seconds is 60 MW, which exceeds 20 MW, the greater of 10% of the BESS gross nameplate (8 MW) or 20 MW.
This IBR performance event is required to be captured by the GO's R1 process.

BESS example 2 – non-qualifying:
BESS facility with gross nameplate power output rating of 80 MW is outputting 40 MW. The BESS facility is curtailed by the RC such that the plant exhibits a near instantaneous active power decrease to 15 MW.

The change in apparent power in under four seconds is 25 MW, exceeding 20 MW, the greater of 10% of the plant's gross nameplate rating (8 MW) or 20 MW. However, the change in apparent power is the result of the RC curtailment which is an exempt event per R1. This IBR performance event is not required to be captured by the GO's Requirement R1 process.

[10] The transmission line fault is assumed not to be on the line connecting the IBR to the system, but rather is a fault remote from the IBR.

Rationale for Requirement R2

Requirement R2 requires analysis of events that meet Requirement R1 thresholds. Requirement R2 also provides an alternative path of event identification by the BA, RC, or TOP. It is anticipated that some events would only be detected by one entity, but the combination of both identification methods would better identify events potentially posing reliability challenges.

Requirement R2 allows 90 days to analyze expected versus actual IBR responses to place an emphasis on diligent resolution, while still allowing enough time to conduct an analysis and identify causes. Ninety days allows adequate time for Generator Owners (GO) to interact with manufacturers and examine capabilities of equipment. This time was chosen to be closer to the PRC-004 timeline of 120 days while recognizing important differences between the application of these standards. PRC-004-4(i) Technical Rationale states "The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed".[11] The PRC-004 timeframe accounts for extreme weather events such as hurricanes that may affect a very large number of Protection Systems for a given responsible entity. The volume of IBR exposed to potential expected operation is anticipated to be lower when compared to Protection Systems and therefore a shorter timeframe is appropriate for PRC-030. The 90-day period starts from the event date for GO-identified performance issues resulting from Requirement R1 or upon request from the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operator (TOP) regarding IBR responses identified during system events.

Requirement R2.1 has subparts to ensure the root cause is identified (R2.1.1); the facility Ride through and reactive power performance is documented (R2.1.2); the issue is assessed and determination whether corrective actions are needed (R2.1.3); and applicability to other similarly designed units is considered (R2.1.4). Collectively, the subparts define the minimum features required as part of an effective analysis. Requirement R2.2 closes the communication loop with BA, RC, and TOP entities, should these entities request analysis results.

Rationale for Requirement R3

Should Requirement R2 determine a need for corrective actions, Requirement R3 requires a CAP or technical justification be developed within 60 calendar days of completing the analysis in Requirement R2, as identified in Part 2.1.3. If R2 did not identify the need for corrective actions, then R3 does not need to be performed.

Resolving the causes of IBR performance issues benefits Buk Power System (BPS) reliability by preventing recurrence. The CAP is an established tool for resolving operational problems. The NERC *Glossary* defines a Corrective Action Plan as, "A list of actions and an associated timetable for implementation to remedy a specific problem." Since a CAP addresses specific problems, the determination of what went wrong needs

[11] Standard PRC-004-4(i) – Protection System Misoperation Identification and Correction. Available at: https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-004-4(i).pdf

to be completed before developing a CAP. When the IBR Performance issue cause(s) is identified in Requirement R2 or Requirement R3 requires Generator Owner(s) to develop a CAP or provide a technical justification that addresses why corrective actions will not be applied nor implemented.

This standard recognizes there may be multiple causes for IBR performance issues. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of an IBR performance issues. The 60-calendar day period for developing a CAP or technical justification is established based on industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent IBR performance issues from reoccurring, the timetable for executing such actions, and an evaluation of the CAP's applicability to the GO's other IBR including those at other locations. The evaluation of these other IBR with similar designs aims to reduce the risk and the likelihood of similar IBR performance issues in other IBRs. The GO is responsible for determining the extent of its evaluation concerning other IBRs and locations. The evaluation may result in the GO including actions to address IBR at other locations or to provide a technical justification that addresses why corrective actions will not be applied nor implemented.

Acceptable technical justification for not performing corrective actions is expected to primarily have two characteristics:
1) interconnection requirements on IBR performance extending beyond those in place at the time of interconnection; and
2) it would require significant material modifications/qualified change.

Technical justifications for not performing corrective actions do not relieve the GO from compliance to other standards (i.e., PRC-029-1 Ride-Through) to the extent that other standards are applicable.

Rationale for Requirement R4
Requirement R4 requires that each entity implement the CAP developed in Requirement R3, as applicable, to mitigate deficiencies identified in Requirement R2. In the NERC *Glossary*, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem."

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. If the CAP is changed, the entity must notify the applicable RC(s), TOP(s), or BA(s). The entity must also notify applicable RC(s) when the CAP has been completed. The implementation of a properly developed CAP ensures that causes of unexpected changes in IBR power output are mitigated in a timely manner.

An IBR deficiency may require the RC to impose operating restrictions so the system can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions should incentivize the entity to complete the CAP as quickly as possible.

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RELIABILITY CORPORATION

Technical Rationale

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1 | July 2024

PRC-030-1 – Unexpected Inverter-Based Resource Event Mitigation

Rationale for Applicability Section
The functional entity responsible for identifying, analyzing, and mitigating unexpected Inverter Based Resources (IBR) performance is the Generator Owner (GO). The Generator Operator (GOP) is not included because of the accountability and coordination issues introduced by listing both GO and GOP as responsible functional entities. Further, this standard intentionally did not include requirements for the Balancing Authority (BA), Reliability Coordinator (RC), and Transmission Operator (TOP) because other standards (e.g., EOP-004) place requirements on these entities for system level events.

General rationale
Aligned with the Project 2023-02 Standards Authorization Request (SAR), the Requirements are structured to identify, analyze, and mitigate IBR performance issues. The SAR discusses how a series of NERC disturbance reports have "identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that these pose". [1,2,3,4,5,6,7,8,9] In particular, IBR performance during events has included tripping or momentary cessation that is unexpected, unwarranted, and poses reliability challenges.

Requirement R1 defines how events are to be identified, along with exceptions that should not be identified. Requirement R2 requires analysis of identified events, with specific elements assessed as

[1] *Odessa Disturbance,* NERC. September 2021.https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf
[2] *2022 Odessa Disturbance,* NERC. Atlanta, GA: December 2022. https://www.nerc.com/comm/RSTC_Reliability_Guidelines/NERC_2022_Odessa_Disturbance_Report%20%281%29.pdf
[3] *900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*, NERC. Atlanta, GA: February 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
[4] *April and May 2018 Fault Induced Solar Photovoltaic Resource Interruption Disturbances Report*, NERC. Atlanta, GA: January 2019. https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf
[5] *Panhandle Wind Disturbance*, NERC. Atlanta, GA: August 2022. https://www.nerc.com/pa/rrm/ea/Documents/Panhandle_Wind_Disturbance_Report.pdf
[6] *Panhandle Wind Disturbance*, NERC. Atlanta, GA: August 2022. https://www.nerc.com/pa/rrm/ea/Documents/Panhandle_Wind_Disturbance_Report.pdf
[7] *1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*, NERC. 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
[8] *San Fernando Disturbance*, NERC. November 2020. https://www.nerc.com/pa/rrm/ea/Documents/San_Fernando_Disturbance_Report.pdf
[9] https://www.iec.ch/conformity-assessment/what-conformity-assessment

described in subparts. Requirement R3 requires a Corrective Action Plan (CAP) or technical justification when corrective actions are needed. Finally, R4 requires mitigation of the performance risk through CAP implementation. The flow of these requirements is summarized in Figure 1.

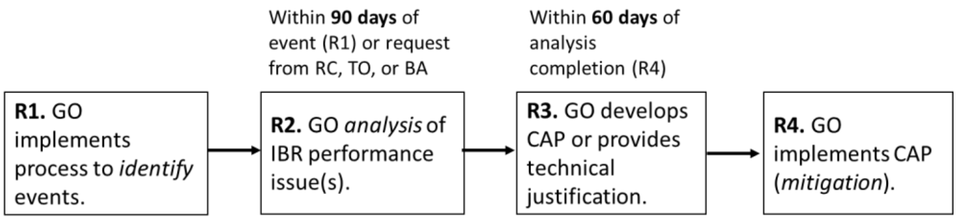

Figure 1.1: Relationship of Requirements in PRC-030-1

The Requirement R1 contains thresholds for identifying events with sudden changes in active power. Figure 1.2 depicts the threshold criteria and logic used in Requirement R1, along with additional details of process flow in Requirement R2.

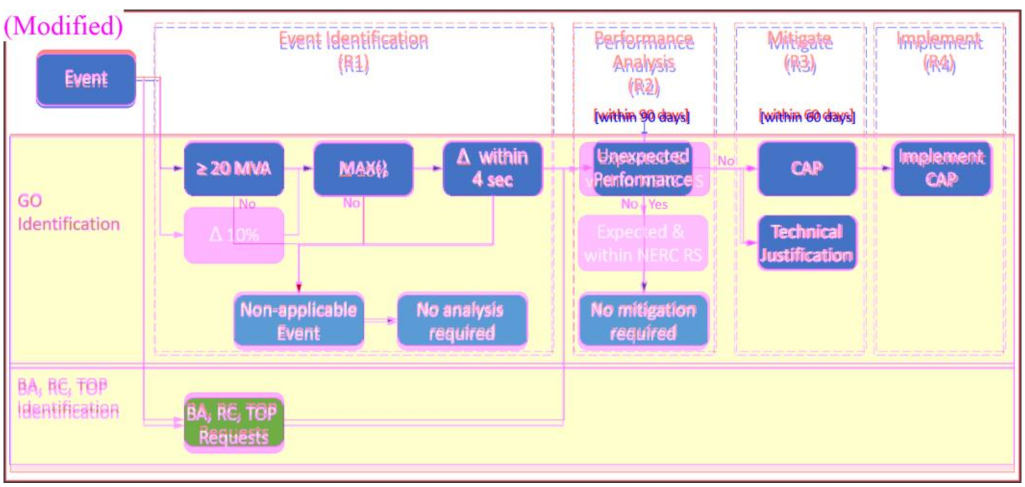

Figure 1.2: PRC-030-1 Flowchart

Rationale for Requirement R1
The intent of Requirement R1 is for the Generator Owner (GO) to implement a documented process to self-identify events that are sufficiently large to warrant an analysis of IBR performance for the identified event. For that reason, the team included the 20 MW minimum threshold, which is a common cutoff for other Reliability Standards, to reduce the number of potential events.

While the GO should consider both active and reactive power responses when an analysis is required, only active power is used as a threshold to trigger analysis. Active power was selected as the monitored parameter to make feasible implementation across IBR plant designs and backend software system (e.g., SCADA).

The thresholds for event identification in R1 effectively provide a two-tier approach depending on the size of the IBR facility. The table below shows the two tiers and the thresholds that should be used to identify events. In addition, all unexpected events in which there is a complete loss of MW output, or active drops to 0 MW, should be identified regardless of plant size and output. This of course excludes planned ramp downs and all other exclusions listed in R1 (solar end of day ramp down, planned outages, loss of connecting transmission facilities, Misoperations identified in PRC-004, etc.).

Facility Nameplate Rating	Threshold
200 MW or less	20 MW
Greater than 200 MW	10% of Nameplate Rating (e.g. 30 MW for 300 MW Facility)

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Nameplate rating was used as the basis of the change (power or amperes) because it is the common reference in NERC and other industry standards. The IBR continuous rating concept outlined in IEEE 2800-2022 definitions was considered and determined to be a departure from NERC standards approaches to date.

The 10% of nameplate rating for magnitude of event threshold was chosen to be large enough to screen out small active power changes but low enough to detect events that should be analyzed for reliability purposes. The percent change is ~~mainly~~ intended to address ~~large units~~facilities with greater than 200 MW nameplate rating where 10% is a significant change, otherwise the 20 MW threshold sets a minimum threshold for event identification. The 20 MW minimum change threshold causes the 10% change to only apply to 200 MW facilities and above.
For smaller capacity facilities, the use of only a percent change as the screening criteria would lead to identification of disturbances that are not likely to be significant for analysis.

~~The intention of the period no longer than four second was to define a sudden change in power, similar to the types of active power loss events described in NERC Disturbance Event reports. The intent is to exclude from review slow power changes expected with normal operations (e.g., variable output from weather, dispatch, planned outages, testing) or expected responses (e.g., loss of interconnection facilities), which were defined as bullet points to Requirement R1.~~
To restate the criteria another way:

- For plants with 0 – 200 MW gross nameplate rating, the change must be at least 20 MW,
- For plants 200 MW gross nameplate rating and larger, the change must be at least 10% of the gross nameplate rating

The criteria could be charted as depicted below.

(Added)

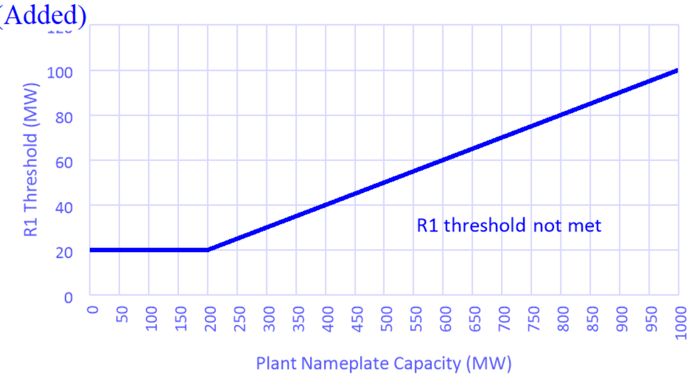

Figure 1.3: R1 MW Threshold Versus Plant Capacity

The purpose of the two limits is to make the trigger points manageable for both large and small facilities. The DT recognizes that as the plant size grows, so does the trigger threshold, that is why the threshold was set at 10% rather than something larger, like 20%. While the GO would not be required to identify events below the 10% threshold for large plants, the RC is explicitly given the option to request a review in the requirement.

The DT revised the wording of R1 to clarify that the DT intent is 20 MW and 10% change, not 20 MW or 10%. While the DT considered the existing criteria sufficient, a complete loss of the facility was also included as an R1 condition.

At one point, the DT considered using the terms sudden and unexpected, but that led to much uncertainty and discussion as to how that would be applied consistently. Therefore, the DT chose to bound the initial change at event onset to a four second timeframe.

The various SCADA scan rates in use at ISOs/RTOs as well as NERC standard minimum required scan rates were considered in selecting four seconds. SCADA monitoring is a likely method for monitoring active power changes. Power changes that occur and recover within one scan are not expected to be detected by the Requirement R1 process implemented by GOs. The four seconds was not intended to define the scan period, but only to characterize the change as sudden when considering information on monitoring capabilities across the industry. If a facility is using a scan rate of four seconds or greater to monitor active power output, the GO should use the change in active power output in one scan rate to identify events meeting R1 criteria. It should be noted that ~~selecting~~using longer time periods or scan rate could lead to a need for more sophisticated event screening or may otherwise lead to identification of more invalid events that occur on slower timescales.

The intention of the four seconds was to limit the time within which the change is calculated. The DT also considered that units following normal operation dispatch commands tend to move more slowly. Using the 20 MW for foursec, the change rate is 5MW/sec or 300 MW/min. Lower ramp rates would not be expected to meet the R1 criteria.

The following set of charts, in Figure 1.4, are examples of expected event scenarios and whether they meet the R1 criteria.

(Added)

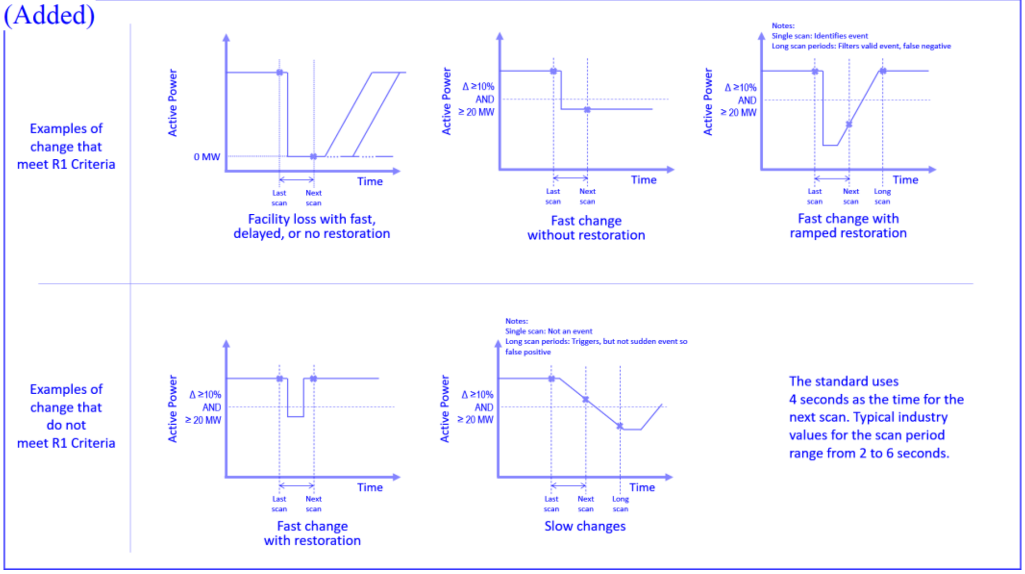

Figure 1.4: PRC-030-1 Flowchart

Due to concern voiced by industry that the thresholds defined in R1 could be often exceeded during the normal operation of an IBR facility, the DT examined three IBR facilities in Texas to determine the frequency of such events.

Solar facility in West Texas with 160 MW nameplate rating:
The DT analyzed one year of data encompassing all of 2023 and found five instances in which the facility changed 20 MW or more within a four second period. All five instances were related to ride-through performance issues previously identified by the RC. There were zero events in which active power

changed 20 MW or more within four second period due to change of irradiance, ramping due to dispatch, or other reasons listed as exclusions in the R1 bullet list.

Wind facility in Texas Panhandle with 300 MW nameplate rating:
The DT analyzed one year of data encompassing all of 2023 and found zero real events in which the facility changed 30 MW or more within a 4 second period. There were several events that were triggered due to drop outs of telemetry from the facility, but telemetry from the POI verified that there were no actual drops in active power from the facility at the time.

Solar Facility in Central Texas with 500 MW nameplate rating:
The DT analyzed one month of data for June 2024 and found seven events in which the facility changed 50 MW or more within a four second period. This facility appears to have curtailment issues and is not following proper ramp rates during curtailment. The plant was either being curtailed or was released from curtailment at the time which four of the seven events were detected. One of those events showed a large increase of irradiance at the time, but it is unclear if the change of irradiance alone caused the sudden increase in generation or if it was due to improper curtailment ramp rates, or a combination of the two. Two of the other events were related to large oscillations lasting up to an hour in which peak to peak magnitude of the oscillation exceeded 50 MW. The last event was due to a Power Plant Controller issue that caused a sudden drop in active power of 246 MW and was previously identified by the RC. Under R1 requirements, three of the seven events would meet criteria and need to be analyzed in R2. The table below summarizes the results:

Date/Time	Four second MW change	Increase/ Decrease	Significant Irradiance Change	Cause	Should be Analyzed in R2
6/4/2024 1:25:00 PM	83	Increase	Yes	Curtailment issue/ Irradiance change?	No (Resource dispatch and/or change in irradiance exclusion)
6/4/2024 5:00:00 PM	192	Increase	No	Curtailment released	No (Resource dispatch exclusion)
6/14/2024 8:02:00 AM	57	Increase	No	Curtailment issue	No (Resource dispatch exclusion)
6/14/2024 11:36:00 AM	138	Increase	No	Curtailment issue	No (Resource dispatch exclusion)
6/17/2024 11:45:00 AM	246	Decrease	No	Plant controller issue	Yes
6/23/2024 12:30:00 PM	50	Both	No	Oscillation Event	Yes (peak to peak magnitude >50 MW observed)
6/26/2024 4:00:00 PM	78	Both	No	Oscillation Event	Yes (peak to peak magnitude >50 MW observed)

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The DT also analyzed data covering one month from four facilities in Hawaii, and found only one event that exceeded thresholds in R1. Since facilities in this area are generally smaller, all four facilities analyzed were less than 200 MW in nameplate rating, so a 20 MW threshold was used for analysis. The DT also looked at an extended time period of 60 seconds, and as expected, more events were identified with the extended time period.

Plant #	1	2	3	4
Technology	Wind	PV	PV/BESS (AC Couple)	BESS Standalone
Facility Nameplate Rating (MW)	69	46	39	135
# of event (4 second, >20 MW)	0	0	0	1 (cause unknown)
# of event (60 second, >20 MW)	0	0	0	8

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Due to the above analysis, the DT believes the thresholds in R1 would rarely trigger events due to normal operation of an IBR facility if the facility is operating as expected. The DT only found one possible instance of a facility exceeding the thresholds due to change of irradiance and wind speed, and it is likely one of those events was caused by improper curtailment ramp rates programmed into the PPC. In addition, the DT reviewed papers published by NREL on Solar PV Variability at Small Timescales and Variability of Wind Power Output, which concludes that change in irradiance and wind speed would not have large impacts to changes in output within a narrow timeframe such as a four second period.

The intention of the four second period was to define a sudden change in power, similar to the types of active power loss events described in NERC Disturbance Event reports. The DT considered using the term “scan period” to define the change period, because this scan period is the basis of the time, but chose to stay with the four second time specification. The four second threshold is meant to provide a significant exclusion because the change must occur quickly, within that time. Increasing the time effectively reduces the rate of change and would identify more events than a four second window. The intent is to exclude from review slow power changes expected with normal operations (e.g., variable output from weather, dispatch, planned outages, testing) or expected responses (e.g., loss of interconnection facilities), which were defined as bullet points to Requirement R1.

The standard four second time only applies to the period of calculating the power change, such as a sudden drop, to be considered valid events. This time qualifies what is a sudden or fast change but does not limit or imply any duration for the entire event. While the change must occur within the four second timeframe, the plant response may take ten’s of seconds or even minutes. The standard does specify and limit that time period.

If the facility output changes and then returns to pre-event levels within 4 seconds (dip and return), then the DT recognizes that would not be an event identified by the criteria. Similarly, because of the randomness of events and data sampling, it is possible that a change of less than four seconds can be identified, but those events technically do not meet the criteria.

The term "changes in active power" encompasses both sudden decreases (i.e., loss of output) and increases (i.e., additional consumption) that may be caused by IBR mis-operations that could affect system reliability. For instance, a battery energy storage system that mis-measures system frequency may unexpectedly enter a charging mode and suddenly increase active power draw.

Photovoltaic (PV) example 1 – qualifying:
PV facility with gross nameplate rating of 220 MW is operating with active output of 80 MW. During a transmission system fault event,[10] the plant exhibits a near instantaneous active power output drop to 50 MW.

The change in apparent power in under four seconds is 30 MW, which exceeds 22 MW, the greater of 10% of the plant's gross nameplate (22 MW) or 20 MW. This IBR performance event is required to be captured by the GO's process implemented in Requirement R1.

PV example 2 – non-qualifying:
PV facility with gross nameplate rating of 80 MW is operating with active output of 60 MW. During a transmission line fault event,[1] the plant exhibits a near instantaneous active power output drop to 42 MW.

The change in apparent power in under four seconds is 18 MW, not exceeding 20 MW, the greater of 10% of the plant's gross nameplate rating (8 MW) or 20 MW. This IBR performance event is not required to be captured by the GO's Requirement R1 process.

Battery Energy Storage System (BESS) example 1 – qualifying:
BESS facility with gross nameplate power output rating of 80 MW is operating as a load drawing 50 MW. During a power plant controller ("PPC") malfunction event of the BESS facility, the PPC incorrectly estimates system frequency sending an incorrect frequency response signal causing the plant to exhibit a near instantaneous change in real power to 10 MW injection.

The change in apparent power in under four seconds is 60 MW, which exceeds 20 MW, the greater of 10% of the BESS gross nameplate (8 MW) or 20 MW.
This IBR performance event is required to be captured by the GO's R1 process.

BESS example 2 – non-qualifying:
BESS facility with gross nameplate power output rating of 80 MW is outputting 40 MW. The BESS facility is curtailed by the RC such that the plant exhibits a near instantaneous active power decrease to 15 MW.

[10] The transmission line fault is assumed not to be on the line connecting the IBR to the system, but rather is a fault remote from the IBR.

The change in apparent power in under four seconds is 25 MW, exceeding 20 MW, the greater of 10% of the plant's gross nameplate rating (8 MW) or 20 MW. However, the change in apparent power is the result of the RC curtailment which is an exempt event per R1. This IBR performance event is not required to be captured by the GO's Requirement R1 process.

Rationale for Requirement R2

Requirement R2 requires analysis of events that meet Requirement R1 thresholds. Requirement R2 also provides an alternative path of event identification by the BA, RC, or TOP. It is anticipated that some events would only be detected by one entity, but the combination of both identification methods would better identify events potentially posing reliability challenges.

Requirement R2 allows 90 days to analyze expected versus actual IBR responses to place an emphasis on diligent resolution, while still allowing enough time to conduct an analysis and identify causes. Ninety days allows adequate time for Generator Owners (GO) to interact with manufacturers and examine capabilities of equipment. This time was chosen to be closer to the PRC-004 timeline of 120 days while recognizing important differences between the application of these standards. PRC-004-4(i) Technical Rationale states "The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed".[11] The PRC-004 timeframe accounts for extreme weather events such as hurricanes that may affect a very large number of Protection Systems for a given responsible entity. The volume of IBR exposed to potential expected operation is anticipated to be lower when compared to Protection Systems and therefore a shorter timeframe is appropriate for PRC-030. The 90-day period starts from the event date for GO-identified performance issues resulting from Requirement R1 or upon request from the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operator (TOP) regarding IBR responses identified during system events.

Requirement R2.1 has subparts to ensure the root cause is identified (R2.1.1); the facility Ride through and reactive power performance is documented (R2.1.2); the issue is assessed and determination whether corrective actions are needed (R2.1.3); and applicability to other similarly designed units is considered (R2.1.4). Collectively, the subparts define the minimum features required as part of an effective analysis. Requirement R2.2 closes the communication loop with BA, RC, and TOP entities, should these entities request analysis results.

Rationale for Requirement R3

Should Requirement R2 determine a need for corrective actions, Requirement R3 requires a CAP or technical justification be developed within 60 calendar days of completing the analysis in Requirement R2, as identified in Part 2.1.3. If R2 did not identify the need for corrective actions, then R3 does not need to be performed.

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Resolving the causes of IBR performance issues benefits Buk Power System (BPS) reliability by preventing recurrence. The CAP is an established tool for resolving operational problems. The NERC *Glossary* defines a Corrective Action Plan as, “A list of actions and an associated timetable for implementation to remedy a specific problem.” Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the IBR Performance issue cause(s) is identified in Requirement R2 or Requirement R3 requires Generator Owner(s) to develop a CAP or provide a technical justification that addresses why corrective actions will not be applied nor implemented.

This standard recognizes there may be multiple causes for IBR performance issues. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of an IBR performance issues. The 60-calendar day period for developing a CAP or technical justification is established based on industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent IBR performance issues from reoccurring, the timetable for executing such actions, and an evaluation of the CAP’s applicability to the GO’s other IBR including those at other locations. The evaluation of these other IBR with similar designs aims to reduce the risk and the likelihood of similar IBR performance issues in other IBRs. The GO is responsible for determining the extent of its evaluation concerning other IBRs and locations. The evaluation may result in the GO including actions to address IBR at other locations or to provide a technical justification that addresses why corrective actions will not be applied nor implemented.

Acceptable technical justification for not performing corrective actions is expected to primarily have two characteristics:
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Technical justifications for not performing corrective actions do not relieve the GO from compliance to other standards (i.e., PRC-029-1 Ride-Through) to the extent that other standards are applicable.

Rationale for Requirement R4
Requirement R4 requires that each entity implement the CAP developed in Requirement R3, as applicable, to mitigate deficiencies identified in Requirement R2. In the NERC *Glossary*, a CAP is: “A list of actions and an associated timetable for implementation to remedy a specific problem.”

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. If the CAP is changed, the entity must notify the applicable RC(s), TOP(s), or BA(s). The entity must also notify applicable RC(s)~~, TOP(s) or BA(s)~~ when the CAP has been completed. The implementation of a properly developed CAP ensures that causes of unexpected changes in IBR power output are mitigated in a timely manner.

An IBR deficiency may require the RC~~, TOP, or BA~~ to impose operating restrictions so the system can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions should incentivize the entity to complete the CAP as quickly as possible.

Unofficial Comment Form

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

Do not use this form for submitting comments. Use the [Standards Balloting and Commenting System (SBS)]() to submit comments on draft three of **PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation** by **8 p.m. Eastern, Monday, August 12, 2024.**

Additional information is available on the [project page](). If you have questions, contact Standards Developer, [Josh Blume]() (email), or at 404-446-2593.

Background Information

Multiple NERC disturbance reports have identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that this undesired performance can pose. Project 2023-02 addresses the reliability-related need by requiring analysis and mitigation of unexpected or unwarranted protection and control operations from IBRs. This includes any types of protections and controls that result in abnormal performance issues within the plant, including abnormal performance resulting in anomalous behavior of active power output from the facility during events.

On October 19, 2023, FERC issued Order No. 901, which directed NERC to develop new or modify existing Reliability Standards that include new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. Project 2023-02 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 a waiver allowing formal comment periods to be reduced from 45 days to as few as 25 calendar days, and final ballot periods to be reduced from 10 days to as few as 5 calendar days in order to help meet the FERC- directed deadline.

Questions

1. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

   ☐ Yes
   ☐ No

   Comments:

2. Does the entity have any concerns regarding the 2023-02 Implementation Plan? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

   ☐ Yes
   ☐ No

   Comments:

3. Provide any additional comments for the Drafting Team to consider, if desired.

   Comments:

Violation Risk Factor and Violation Severity Level Justifications

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

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 Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues. 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 Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric 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 Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric 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 Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric 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 Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric 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 Electric System, or the ability to effectively monitor and control the Bulk Electric 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 Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric 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-030-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because not having a process for identifying changes in active power output, which is required in defining the minimum standards will be performed, could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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 medium 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-030-1, Requirement R1	
Proposed VRF	**Medium**
than One Obligation	

VSLs for PRC-030-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity failed to implement a documented process to identify changes in Real Power output in accordance with Requirement R1.

VSL Justifications for PRC-030-1, 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.
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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VRF Justifications for PRC-030-1, Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because a Generator Owner not analyzing it's Inverter Based Resource's performance which are required in defining the minimum standards will be within 90 days of an event, identified pursuant to Requirement R1 or receipt of a request pursuant to Requirement R2, to address the unexpected change(s) in power output and the applicability to its other IBR facilities that could be affected by the same cause of unexpected change(s) in power output could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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	This VRF is in line with the definition of a medium VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-030-1, Requirement R2	
Proposed VRF	**Medium**
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-030-1, Requirement R2

Lower	Moderate	High	Severe
The responsible entity performed an analysis in accordance with Requirement R2, but in more than 90 calendar days but less than 120 calendar days of first identifying an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 120 or more calendar days but less than 150 calendar days of first identifying an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 150 or more calendar days but less than 180 calendar days of first identifying an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 or Part 2.1.4. OR The responsible entity failed to provide the analysis results from the requesting entity in accordance with Requirement R2, Part 2.2.	The responsible entity developed an analysis in accordance with Requirement R2, but in 180 calendar days or more of first identifying an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 and Part 2.1.4. OR The responsible entity failed to document the facility's ride-through performance in accordance with Requirement R2, Part 2.1.2

			OR The responsible entity failed to determine the susceptibility of other inverter-based resource facilities in accordance with Requirement R2, Part 2.1.3.

VSL Justifications for PRC-030-1, 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 Ambiguous Language	The proposed VSLs are not 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-030-1, Requirement R2	
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-030-1, Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because a Generator Owner's failure to develop either a Corrective Action Plan (CAP), or technical justification that addresses why corrective actions will not be applied nor implemented for it's Inverter Based Resource's could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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	This VRF is in line with the definition of a medium VRF requirement per the criteria filed with FERC as part of the

VRF Justifications for PRC-030-1, Requirement R3	
Proposed VRF	**Medium**
Guideline 4- Consistency with NERC Definitions of VRFs	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-030-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 60 days, but provided it within 90 days.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 90 days, but provided it within 120 days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 120 days, but provided it within 150 days OR The developed CAP did not include corrective actions for other facilities owned by the Generator Owners as identified in Requirement R2 Part 2.1.3, if necessary. OR The developed CAP or technical justification was not provided to	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented, within 150 calendar days.

		the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator.	

VSL Justifications for PRC-030-1, 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 not 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-030-1, Requirement R3	
Number of Violations	

VRF Justifications for PRC-030-1, Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because failure to implement, update, or notify with the applicable Reliability Coordinator (RC) the Corrective Action Plan (CAP) for it's Inverter Based Resource's could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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 medium 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-030-1, Requirement R4	
Proposed VRF	**Medium**
than One Obligation	

VSLs for PRC-030-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R4.

VSL Justifications for PRC-030-1, 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	The proposed VSLs are not 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-030-1, 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.

Mapping Document
Consideration of FERC Order 901 Directives

Project 2023-02 Unexpected Inverter-Based Resource Event Mitigation
July 2024

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, there 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.

FERC Order 901 Directives	
Directive Language	**Consideration of Directives**
P58. 208 "Further, the Reliability Standards must require generator owners to communicate to the relevant planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities the actual post-disturbance ramp rates and the ramp rates to meet expected dispatch levels (i.e., generation-load balance)."	The Drafting Team addressed this directive in proposed PRC-030-1 through Requirements R1, R2, R3, and R4. Requirement R1 requires GOs to implement a documented process to identify any complete facility loss of output or certain changes in Real Power output. Requirement R1 also includes exclusions to these identification measures.

[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

	Requirement R2 requires that GOs, within 90 calendars of identifying a Real Power change under Requirement R1 or a request from the applicable RC, BA, or TOP that identified a Disturbance and change in IBR Real Power output, to analyze IBR facility performance during the event, and, provide the analysis results to the requesting applicable RC, BA, or TOP. Requirements R3 and R4 require the GO to develop a Corrective Action Plan (CAP), implement the CAP, and update the CAP if actions or timetables change. The GO will need to notify and provide the CAP, or the justification why no corrective actions are needed, to the applicable entity.

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Standards Announcement

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

Formal Comment Period Open through August 12, 2024

Now Available

A formal comment period for draft three of **PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation** 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 Board 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.

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 Standards Developer, Josh Blume (via email) or at 470-755-0346. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues observer list" in the Description Box.

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Comment Report

Project Name:	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues | Draft 3
Comment Period Start Date:	7/22/2024
Comment Period End Date:	8/12/2024
Associated Ballots:	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Implementation Plan AB 3 OT 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues PRC-030-1 AB 3 ST

There were 60 sets of responses, including comments from approximately 151 different people from approximately 105 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

2. Does the entity have any concerns regarding the 2023-02 Implementation Plan? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

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
					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
					Greg Campoli	NYISO	1	NPCC
					Matt Goldberg	ISO New England	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Elizabeth Davis	PJM	2	RF
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
					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
					Amber Skillern	East Kentucky Power Cooperative	1	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 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	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power	10	NPCC

Coordinating Council						Coordinating Council		
					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
Ryan Strom	Ryan Strom		RF	Buckeye Power Group	Carl Spaetzel	Buckeye Power, Inc.	3	RF
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Kevin Zemanek	Buckeye Power, Inc.	5	RF
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 believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy supports the scope of this standard and finds no alternatives or more cost-effective options for consideration.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Revisit PRC-030-2 Standard within 2-years to allow applicable personnel cognizant of its capabilities to be better prepared to recognize cost-effective options or recommendations to answer this question.	
Likes 0	
Dislikes 0	

Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
Avista agrees with EEI Comments	
Likes 0	
Dislikes 0	
Response	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI has no suggested alternatives over what has been proposed within PRC-030-1.	
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	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	

We concur with EEI's comments.

Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPC has signed on to ACES comments:

It is the opinion of ACES that PRC-030-1 Requirement R1 should be more aligned with PRC-004-6 Requirement R1. In short, we believe that requiring a documented process to identify applicable events at an IBR, as is currently required by PRC-030-1 R1, increases the compliance burden for the GO with no appreciable decrease in the risk to the BPS. Therefore, we recommend striking the phrase “implement a documented process to” from PRC-030-1 Requirement R1. The revised version of R1 would thus read as follows:

R1. Each applicable Generator Owner shall 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 4 second period. 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 IBR generator; or

• Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.

Secondly, ACES does not agree with the RC, BA, or TOP being able to require the GO to perform an analysis of any event type chosen by the RC, BA, or TOP. We believe that the event types identified by the RC, BA, or TOP should be inline with the event types identified by the GO in R1. Thus, we recommend modifying Requirement R2 as follows:

R2. Each applicable Generator Owner shall perform the activities identified in each subpart of this Requirement, within 120 calendar days, of either:

• identifying a Real Power change event pursuant to Requirement R1 or,

• receiving a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator wherein the requesting entity identified an event meeting the thresholds established in Requirement R1

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in Real Power output;

2.1.2. Document the facility's Ride-through performance including Reactive Power response during the event;

2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities.

2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator.

Furthermore, it is the opinion of ACES that the GO should not be required to submit a CAP to the RC, BA, nor TOP. This is not inline with the requirements identified in PRC-004-6 Requirement R6 nor does it add any appreciable reduction in risk while at the same time increasing the compliance burden for the GO and possibly the RC, BA, and/or TOP. In other words, why should the GO submit its CAP to these entities if they are not required to perform any action(s) upon receipt?

Lastly, requirements R3 and R4 of the proposed PRC-030-1 do not align with one another. For example, as written, R3 requires a CAP be provided to the RC, BA, and TOP whereas R4 Part 4.3 only requires that the RC be notified. We recommend removing the any portion of these requirements that require the GO to submit a CAP to the RC, BA, and/or TOP.

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1

Answer	No
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	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	No
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	No
Document Name	
Comment	
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	
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	
Likes 0	
Dislikes 0	
Response	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
SMEs responded with the following comments: • "Although this is a better version than the previous draft, and it more specifically gets to the root of what the need is, this standard is still an extension of MOD-033 and PRC-002, and now also PRC-004. There does not seem to be enough justification to add a separate standard (and the additional personnel hours required to fulfill it) when the effects could likely be accomplished by updating existing standards."	
Likes 0	
Dislikes 0	
Response	

Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
A more cost-effective way would be to let the Transmission Operator identify the events for which service data needs to be studied. Have the Generation Plants responsible for providing that data. Evaluating all potential events results in more work that may or may not provide benefit to the Bulk Power System.	
Likes 0	
Dislikes 0	
Response	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	Yes
Document Name	
Comment	
“Although this is a better version than the previous draft, and it more specifically gets to the root of what the need is, this standard is still an extension of MOD-033 and PRC-002, and now also PRC-004. There does not seem to be enough justification to add a separate standard (and the additional personnel hours required to fulfill it) when the effects could likely be accomplished by updating existing standards.”	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Tri-State agrees with the comments provided by the MRO NSRF.	
Likes 0	
Dislikes 0	

Response	
Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

1. We believe the original directive extracted from the last sentence of Paragraph 208 of FERC Order No. 901 has been taken out of context. According to Paragraph 208, as identified by the Standards Drafting Team (SDT) as the purpose for the proposed NERC Reliability Standard PRC-030-1, the Commission directed NERC to develop a "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. The proposed Reliability Standards must account for the technical differences between registered IBRs and synchronous generation resources, such as registered IBRs' faster control capability to ramp power output down or up when capacity is available. Further, the Reliability Standards must require generator owners to communicate to the relevant planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities the actual post-disturbance ramp rates and the ramp rates to meet expected dispatch levels (i.e., generation-load balance)." If should be noted that most of this paragraph is currently being addressed under NERC Standard Development Project2020-02, Modifications to PRC-024 (Generator Ride-through). If the purpose of NERC Reliability Standard PRC-030-1 is to require Generator Owners to communicate the actual post-disturbance ramp rates and the ramp rates to meet expected dispatch levels and provide that information to other entities, we believe a simpler approach could be taken.
2. For instance, there are already data provisions requirements under NERC Reliability Standard MOD-032-1, IRO-010-5, and TOP-003-5 for entities to include in their data specifications to "request" data like ramp rates to meet expected dispatch levels from Generator Owners. Hence, NERC Reliability Standard PRC-030-1 should be condensed to only provide actual ramp rate (operational) data following a Disturbance. This is like the data request concepts listed within the proposed NERC Reliability Standard PRC-028-1. In that Standard, data is provided to a requested entity based on an observed exception to normal operations. As currently proposed, the Generator Owner has as little 15 calendar days to provide data over a 20-calendar day period. We believe a similar approach should be followed in NERC Reliability Standard PRC-030-1 and allow the Generator Owner 15 calendar days to work with their Generator Operator to collect operational data, including actual ramp rates, that were recorded during a period before, during, and after a Disturbance.

Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 5	
Answer	Yes
Document Name	
Comment	

We are highly concerned that, relative to the first draft, the current draft of the standard reduces the threshold for output change events that must be reviewed to determine if they need to be analyzed. The revised standard sets the threshold at a change in output that is greater than 10% of the plant's nameplate rating (and greater than 20 MW) within 4 seconds, relative to the threshold of 20% within 2 seconds in the initial draft. This change only adds to our concerns about the generator owner's burden of manually reviewing each output change to exclude events caused by normal fluctuations in plant output due to weather, dispatch, and other factors. No mechanism exists for generator owners to automatically exclude those permissible changes from consideration. Wind and solar plants have a limited number of meteorological towers and pyranometers for measuring the available wind and solar resource, respectively, which makes it difficult in many cases to precisely determine whether changes in output across a plant were caused by resource availability.

The new lower threshold will pick up many more such events, as changes of 10% output within 4 seconds can routinely occur at solar and wind plants. As we explained in our previous comments, the passage of clouds over medium-sized solar plants can cause changes in output that are larger than this threshold.[1] As a result, in some cases a large share of the events a generator owner is required to review will be these normal changes in output, diverting their time and resources away from addressing real reliability concerns.

The drafting team's response to our comments in the first round of balloting only reinforces our concern about the burden imposed on the generator owner: "GOs would not know if it was unexpected behavior of generator settings and controls until the analysis is performed. The exceptions that have been moved from the footnote to the Standard Language allow for GOs to dismiss events due to cloud cover, change in wind speed. etc. Outage/Fault codes would be reviewed during the analysis process. It will be up to GOs to develop a process to identify events that that do not fit into the listed exclusions and require further analysis." It is highly burdensome for a generator owner to pull turbine- or inverter-level fault codes and plant-level fault codes for each event with a more than 10% change in output. Moreover, the drafting team cannot ignore the excessive and unworkable burden imposed on generator owners by simply dismissing that with "It will be up to GOs to develop a process to identify events that that do not fit into the listed exclusions and require further analysis."

As explained in our answer to question 2 below, the best solution to these concerns may be to remove most if not all of R1, and instead rely on analysis requests initiated by the Reliability Coordinator, Balancing Authority, or Transmission Operator following a disturbance event that causes a drop in generator output per R2.

Second, we are concerned that generator owners will be required to conduct a full analysis of all events in which an IBR plant reduces real power output to prioritize reactive power output, as is desirable and expected during voltage disturbances. The standard should be revised to include a mechanism to automatically screen out disturbance events in which the IBR generator briefly reduced real power output because it entered reactive power priority mode.

During a voltage disturbance on the bulk power system, the most helpful response is typically for generators to shift some of their power output from providing real power to prioritizing reactive power to help prevent voltage collapse.[2] As experts at the Energy Systems Integration Group (ESIG) explain, summarizing the conclusions of a recent workshop on generator interconnection, "If too much active power is injected into a point of interconnection with already depressed voltage, it may further collapse the voltage, causing more cascading outages and compromising the reliability of the grid. Rather than keeping the active power of an IBR at a pre-disturbance level, it is more beneficial to reduce active power, depending on severity of voltage drop thus preventing further voltage collapse — while reactive power is prioritized and increased to support grid and terminal voltage."[3]

Not only does a requirement to maintain active power production instead of prioritizing reactive power production during a voltage disturbance risk exacerbating voltage collapse, but it is also infeasible in many cases. If the voltage is low during and following a disturbance, even if an IBR plant continues to inject its full pre-disturbance level of active current, it cannot maintain the level of active power it was delivering because voltage is now lower and active power is the product of voltage and current. Moreover, to increase reactive power injection, a generator must typically shift its output away from active power injection (power is comprised of active and reactive components). Both synchronous and asynchronous generators have a finite ability to produce power, so they must reduce real power (P) production to increase reactive power (Q) along the P-Q generator capability curve. In most cases, it is infeasible for any type of generator to maintain active power production while also increasing reactive power output during a disturbance.

Solutions

To address the concerns expressed in our answer to question 1 above regarding the burden on generators of screening out changes in output that are not caused by disturbances, the best solution may be to remove most if not all of R1, and instead rely on analysis requests initiated by the Reliability Coordinator, Balancing Authority, or Transmission Operator following a disturbance event per R2. This would remove the inefficient "needle in the haystack" burden on generators under R1 to screen every output change event to find the small subset that are due to disturbances, and instead only focus resources on reviewing significant disturbance events that coincided with a change in generator output. Because many generators do not have synchrophasors or other equipment required to determine when significant grid disturbances have occurred, it makes more sense for the analysis to be initiated by a request from the RC, BA, or TO. Relatedly, we reiterate our request from the first comment period to add a requirement to R2 that the RC, BA, or TO must file its request within 15 days of the disturbance event. This will ensure that the GO has at least five days to pull data before it is overwritten, given that the data retention period in the current draft of PRC-028 R7 is 20 days.

As explained above, the standard should also be revised to include a mechanism to exclude analysis of disturbance events in which the IBR generator briefly reduced real power output because it entered reactive power priority mode.

Finally, the requirement on the generator owner in 2.1.4 to "Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities" appears to be unreasonable if not unworkable. A company that owns multiple IBR plants typically uses different equipment and settings across its plants, and some may be wind plants while others are solar plants, so there is no reason to assume its other plants have the same susceptibility simply because they have the same owner. At minimum, the requirement should be clarified to specify whether projects owned by the same parent company but that are incorporated as separate LLCs must be assessed as part of compliance with 2.1.4., and other such details.

If PRC-30 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, these changes would help to secure sufficient support for the standard to pass during re-balloting.

{C}[1]{C} https://www.sciencedirect.com/science/article/abs/pii/S0306261917300144

{C}[2] https://www.esig.energy/download/interconnection-requirements-need-for-harmonization-jason-macdowell/?wpdmdl=9267&refresh=62f587eab15591660258282, at 6

{C}[3]{C} https://www.esig.energy/wp-content/uploads/2022/10/Joint-Generator-Workshop-Summary-1.pdf, at 29

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 Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 1

Likes 0	
Dislikes 0	

Response

Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock

Answer	Yes
Document Name	
Comment	

TransAlta supports Entergy's comment:

"A more cost-effective way would be to let the Transmission Operator identify the events for which service data needs to be studied. Have the Generation Plants responsible for providing that data. Evaluating all potential events results in more work that may or may not provide benefit to the Bulk Power System."

Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	Yes
Document Name	
Comment	

The NAGF membership is concerned with the time/effort required to perform event identification and post-event performance validation. Even with automation, the process will require Generator Owner (GO) personnel to analyze and identify those IBR facility power change events that require corrective actions. The NAGF members believe that this will impose a significant human capital burden for GO registered entities.

Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5

Answer	Yes
Document Name	
Comment	

Constellation aligns with the NAGF 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	Yes
Document Name	
Comment	
The MRO NSRF does not believe that this is cost-effective as currently proposed. Please see the MRO NSRF's other responses to questions. Perhaps determining subsections of the North American electric grid where this detailed monitoring and analysis is most needed rather than requiring it across the entire geographic area. The system stiffness to voltage and frequency fluctuations should be accounted for in regions where the IBR facilities are not likely to be affected by abnormal system condition events. Any possible reduction in the number of facilities required to install this equipment is a direct cost reduction.	
Likes 1	Western Area Power Administration, 1, Hammer Ben
Dislikes 0	
Response	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Capital Power supports the NAGF's comments: *The NAGF membership is concerned with the time/effort required to perform event identification and post-event performance validation. Even with automation, the process will require Generator Owner (GO) personnel to analyze and identify those IBR facility power change events that require corrective actions. The NAGF members believe that this will impose a significant human capital burden for GO registered entities.*	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	

Constellation aligns with NAGF 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	Yes
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	Yes
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	

NERC and FERC should allow PRC-024-3 and PRC-029 to be implemented to allow for corrections/requirements to take place and then evaluate if PRC-030 and its requirements as currently proposed are actually needed.

Likes 0	
Dislikes 0	

Response

Ryan Strom - Ryan Strom On Behalf of: Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; Tom Schmidt, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group

Answer	Yes
Document Name	

Comment

Buckeye supports the comments made by ACES:

It is the opinion of ACES that PRC-030-1 Requirement R1 should be more aligned with PRC-004-6 Requirement R1. In short, we believe that requiring a documented process to identify applicable events at an IBR, as is currently required by PRC-030-1 R1, increases the compliance burden for the GO with no appreciable decrease in the risk to the BPS. Therefore, we recommend striking the phrase “implement a documented process to” from PRC-030-1 Requirement R1. The revised version of R1 would thus read as follows:

R1. Each applicable Generator Owner shall 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 4 second period. 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 IBR generator; or
• Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.
Secondly, ACES does not agree with the RC, BA, or TOP being able to require the GO to perform an analysis of any event type chosen by the RC, BA, or TOP. We believe that the event types identified by the RC, BA, or TOP should be inline with the event types identified by the GO in R1. Thus, we recommend modifying Requirement R2 as follows:
R2. Each applicable Generator Owner shall perform the activities identified in each subpart of this Requirement, within 120 calendar days, of either:
• identifying a Real Power change event pursuant to Requirement R1 or,
• receiving a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator wherein the requesting entity identified an event meeting the thresholds established in Requirement R1
2.1. Analyze its IBR facility performance during the event, including:
2.1.1. Determine the root cause(s) of change(s) in Real Power output;

2.1.2. Document the facility’s Ride-through performance including Reactive Power response during the event;
2.1.3. Assess any performance issues identified and if corrective actions are needed; and
2.1.4. Determine the applicability of the root cause(s) to the Generator Owner’s other Inverter-Based Resource facilities.
2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator.
Furthermore, it is the opinion of ACES that the GO should not be required to submit a CAP to the RC, BA, nor TOP. This is not inline with the requirements identified in PRC-004-6 Requirement R6 nor does it add any appreciable reduction in risk while at the same time increasing the compliance burden for the GO and possibly the RC, BA, and/or TOP. In other words, why should the GO submit its CAP to these entities if they are not required to perform any action(s) upon receipt?
Lastly, requirements R3 and R4 of the proposed PRC-030-1 do not align with one another. For example, as written, R3 requires a CAP be provided to

the RC, BA, and TOP whereas R4 Part 4.3 only requires that the RC be notified. We recommend removing the any portion of these requirements that require the GO to submit a CAP to the RC, BA, and/or TOP.	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - PNM Resources - 1,3,5 - WECC	
Answer	Yes
Document Name	
Comment	

Please consider the following:

1. Overlap with Existing Standards: The new standard is seen as an extension of existing standards (MOD-033, PRC-002, PRC-004) and may not justify the additional personnel hours required.

2. Cost-Effectiveness: A more efficient approach would be for Transmission Operators to identify necessary service data events and have Generation Plants provide the data, rather than evaluating all potential events.

3. Clarification of Directives: The original directive from FERC Order No. 901 has been taken out of context. The proposed standard should focus on providing actual ramp rate operational data following disturbances.

4. Existing Data Provisions: There are already data provision requirements under other NERC standards (MOD-032-1, IRO-010-5, TOP-003-5) that could be utilized.

5. Targeted Monitoring: Detailed monitoring and analysis should be focused on specific sections of the grid where it is most needed, rather than across the entire geographic area, to reduce costs.

Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	

As currently drafted, Invenergy believes PRC-030-1 imposes a significant resource burden on GOs without commensurate benefit to reliability. Considerable amounts of time will be required to identify, analyze, and validate every event involving a power change of the applicable magnitude. As an alternative, the SDT could consider revising R1 to require Generator Owners to analyze events only upon request by the applicable Transmission

Operator, Balancing Authority, or Reliability Coordinator. This would allow the Generator Owner to focus its resources and efforts on analyzing events of significance to the BES.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	
As currently drafted, Invenergy believes PRC-030-1 imposes a significant resource burden on GOs without commensurate benefit to reliability. Considerable amounts of time will be required to identify, analyze, and validate every event involving a power change of the applicable magnitude. As an alternative, the SDT could consider revising R1 to require Generator Owners to analyze events only upon request by the applicable Transmission Operator, Balancing Authority, or Reliability Coordinator. This would allow the Generator Owner to focus its resources and efforts on analyzing events of significance to the BES.	
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	
It is the opinion of ACES that PRC-030-1 Requirement R1 should be more aligned with PRC-004-6 Requirement R1. In short, we believe that requiring a documented process to identify applicable events at an IBR, as is currently required by PRC-030-1 R1, increases the compliance burden for the GO with no appreciable decrease in the risk to the BPS. Therefore, we recommend striking the phrase “implement a documented process to” from PRC-030-1 Requirement R1. The revised version of R1 would thus read as follows: R1. Each applicable Generator Owner shall 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 4 second period. 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 IBR generator; or • Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.	

Secondly, ACES does not agree with the RC, BA, or TOP being able to require the GO to perform an analysis of any event type chosen by the RC, BA, or TOP. We believe that the event types identified by the RC, BA, or TOP should be inline with the event types identified by the GO in R1. Thus, we recommend modifying Requirement R2 as follows:

R2. Each applicable Generator Owner shall perform the activities identified in each subpart of this Requirement, within 120 calendar days, of either:

· identifying a Real Power change event pursuant to Requirement R1 or,

· receiving a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator wherein the requesting entity identified an event meeting the thresholds established in Requirement R1

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in Real Power output;

2.1.2. Document the facility's Ride-through performance including Reactive Power response during the event;

2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities.

2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator.

Furthermore, it is the opinion of ACES that the GO should not be required to submit a CAP to the RC, BA, nor TOP. This is not inline with the requirements identified in PRC-004-6 Requirement R6 nor does it add any appreciable reduction in risk while at the same time increasing the compliance burden for the GO and possibly the RC, BA, and/or TOP. In other words, why should the GO submit its CAP to these entities if they are not required to perform any action(s) upon receipt?

Lastly, requirements R3 and R4 of the proposed PRC-030-1 do not align with one another. For example, as written, R3 requires a CAP be provided to the RC, BA, and TOP whereas R4 Part 4.3 only requires that the RC be notified. We recommend removing the any portion of these requirements that require the GO to submit a CAP to the RC, BA, and/or TOP.

Likes 0	
Dislikes 0	

Response

Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC

Answer	Yes
Document Name	

Comment

NV Energy agrees with the NSRF comments that the proposed is no a cost-effection solution.

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	
Richard Vendetti - NextEra Energy - 5	
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	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	

Black Hills Corporation will not comment on alternatives or cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	
Document Name	
Comment	
NRG Energy Inc is in support of the comments made by EPSA.	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	
Document Name	
Comment	
NRG agrees with the EPSA comments.	
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	
ITC has no comments	

Likes 0	
Dislikes 0	

Response

Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers

Answer	
Document Name	

Comment

Ameren has no comment on the cost effectiveness of this project.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 3,4,5,6

Answer	
Document Name	

Comment

NCPA understands Ferc Order 901 and does not oppose it.

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.

Basically, what we are being asked to do is 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	
No comment	
Likes 0	
Dislikes 0	
Response	

2. Does the entity have any concerns regarding the 2023-02 Implementation Plan? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
We support EEI's comments.	
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	

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI has no concerns with the Implementation Plan for PRC-030-1	
Likes 0	
Dislikes 0	
Response	

Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF.	
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	

Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
Avista agrees with EEI comments	
Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No

Document Name	
Comment	
Consider implementing a 2028 implementation date instead of 2027 since most companies have already committed resources relative to bids, etc.; expensive design change requests will be required using the proposed date.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
None	
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 has no concern with the Implementation Plan	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy offers no comments toward the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
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	No
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	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Colin Chilcoat - Invenergy LLC - 6	
Answer	No
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	No
Document Name	

Comment

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

Likes 0	
Dislikes 0	

Response

Ryan Strom - Ryan Strom On Behalf of: Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; Tom Schmidt, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Megan Melham - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Bruce Walkup - Arkansas Electric Cooperative Corporation - 6

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	

WECC voted yes but offers the following comments/concerns:

PRC-030- Separating the Requirements out by design and operation is not realistic and gives the false appearance of being applicable prior to Jan 1, 2030. The language of the Requirements, as written, are unenforceable from a design perspective for BES IBRs and non-BES IBRs.

Design aspects for the Requirement appear to be as follows (If not DT needs to explicitly explain what the "design" portion of the Requirement language is so that everyone—registered entities, Regions, NERC, and FERC are on the same page) :

R1- Process has to be designed by effective date of Standard for BES IBRs or (later of Jan 1, 2027 or effective date for non-BES IBRs). Effectively review of compliance can not be completed on design as the Requirement language is to "implement" a documented process. If an entity has not designed the "process", it seems the entity would be non-compliant, but the Requirement is unenforceable. The process can not be implemented unless an event occurs which is an operational concern with different timelines. R2 through R4 all depend upon an event occurring.

It also appears that R2-R4 would be unenforcecable as written, becuase if R1 was not complied with, R2 would not be enforceable. If R2 was not complied with, R3 would not be doable and if R3 was not complied with, R4 would not be enforceable.

Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	Yes
Document Name	
Comment	

Six months after FERC approval is unreasonable to have equipment and procedures in place. Especially considering several entities will need to order and install new monitoring equipment from most likely the same companies. The implementation plan should be the same as PRC028.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	Yes
Document Name	

Comment

WEC Energy Group has a concern with following statements from the Implementation plan:

Bulk-Electric System IBRs: Entities shall comply with the portion of Requirements R1, R2, R3 and R4 relating to the ***design*** *of their BES IBRs to meet the requirements by the effective date of the standard.*

Please clarify what is the "**design**" portion of requirements R1, R2, R3 and R4. If the "design" cannot be clarified, then only R1 should be met by the effective date of the standard and R2, R3 and R4 should follow upon implementation of PRC-029.

Performance-Based Elements (all applicable IBRs) Entities shall not be required to comply with the portion of Requirements R1, R2, R3, and R4 relating to the ***operation*** *of IBRs to meet the requirements until the entity has established the required Ride-through capabilities for those IBRs in accordance with the implementation plan for Reliability Standard PRC-029-1.*

Please clarify what is the "**operation**" portion of requirements R1, R2, R3 and R4.

Likes 0	
Dislikes 0	

Response

Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers

Answer	Yes
Document Name	

Comment

Ameren recommends an 18-month implementation plan to allow sufficient time for entities to develop a plan as well as to procure and install the necessary equipment.

Likes 0	

Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
The implementation period should be increased from 12 months to 36 months to allow for any equipment changes or upgrades needed to comply with the standard.	
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	
Extensive detail is required to clarify between design stages and actual operation for phased-in implementation.	
Likes 0	
Dislikes 0	

Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation aligns with NAGF comments. Kimberly Turco on behalf of Constellation Energy Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation aligns with the NAGF comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	Yes
Document Name	
Comment	
The implementation plan is unnecessarily convoluted. PRC-030 R1 requires entities to have a documented process, then R2/R3/R4 requires entities to exercise the process which depends on having sufficient SER/FR/DDR equipment installed as per PRC-028. Simply tie the timing of the PRC-030 implementation plan to PRC-028.	

Thus, TransAlta proposes to have R1 in place by the effective date of the standard, and R2/R3/R4 in place as the disturbance equipment is installed at the respective IBRs as per PRC-028.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

1. We believe the removal of NERC Reliability Standard PRC-028-1 from the list of Prerequisite Standard(s) is unnecessary. If a Generator Owner is required to provide operational data from a Disturbance impacting their IBR facility, then recorded measurement data associated with that Disturbance would be critical to any post-disturbance analysis. We believe NERC Reliability Standard PRC-028-1 should be added to the list of Prerequisite Standard(s).
2. 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.

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

SMUD agrees with the comments submitted by Tennessee Valley Authority.

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 supports comments made by Entergy.

Likes 0	
Dislikes 0	
Response	

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

While we appreciate the change from 6 months to 12 months, this still may not provide enough time for the work to be done considering that the GO may not have the required expertise in-house and, thus, may have to contract the work out to a potentially small number of companies that can do the work. The time it takes to develop a statement of work, issue requests for quotes, obtain the quotes, evaluate the quotes, and issue purchase orders can easily be 6 months. Then the work has to be done by the contractor, reviewed by the GO, any GO comments addressed by the contractor, then re-reviewed by the GO to ensure their comments were addressed, and finally issued by the contractor. Depending on the workload and availability of contractors, getting this done within a possible 6 month timeframe is not necessarily reasonable. We request that the effective date be moved to at least 24 months.

The non-BES compliance date of January 1, 2027, only gives 7 months from the assumed potential registration date of May 2026. While currently non-registered GOs could start the design process early, they may not know if they will be required to be registered until closer to the May 2026 deadline and this won't give them enough time to get work done or will potentially require them to do work that is not required (if they wind up not having to register). Suggest moving this date out to January 1, 2028.

If the IBR operation doesn't have to be changed until the implementation of PRC-029-1, and if the PRC-029-1 gives some number of years to be compliant, which it should, why does the design need to be done withing one year us tot potentially "sit on a shelf" for a few years?

Likes 0	
Dislikes 0	
Response	

Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	

Comment	
This is not a phased in implementation plan. Also, Entergy is concerned that the implementation of PRC-030 is dependent on the implementation of PRC-029 which has not been approved yet. The implementation plan should be 365 days instead of 90 days to allow for any control changes that might be required. A process may need to be added to allow extensions of implementation based on potential supply chain issues.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP has no objections for the implementation period to be twelve months for purposes of identification, however a separate implementation period needs to be established for those cases where field equipment modifications are necessary for detecting changes to Real Power. This may not be a simple “configuration issue”, as new equipment may be needed to obtain additional data points as it is not explicitly stated in R1 where the measurement needs to be taken. AEP suggests adding text to clarify the measure point as “individually, at each MPT level”, “at the POI”, or some other defined point. AEP recommends that an implementation period of 18 months be allowed instead to accomplish whatever field modifications may be necessary.	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - PNM Resources - 1,3,5 - WECC	
Answer	
Document Name	
Comment	

Please consider the following:

1. Timeframe for Compliance: While extending the compliance period from 6 to 12 months is appreciated, it may still be insufficient due to the need for contracting out work, which involves a lengthy process. A 24-month period is suggested.

2. Non-BES Compliance Date: The proposed compliance date of January 1, 2027, is too soon after the potential registration date of May 2026. Extending this to January 1, 2028, is recommended.

3. Design Implementation: If PRC-029-1 allows several years for compliance, the design work required within one year may be premature and unnecessary.

4. Prerequisite Standards: The removal of PRC-028-1 from the list of prerequisite standards is seen as unnecessary. Including it would ensure critical data for post-disturbance analysis is available.

5. Coordination of Implementation Plans: NERC should align the implementation plans for related standards to provide a unified set of compliance dates, simplifying tracking for Generator Owners.

6. Simplification of Implementation Plan: The current plan is considered convoluted. It is suggested to tie the timing of PRC-030 implementation to PRC-028, with phased compliance dates

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	

ITC has no comments

Likes 0	
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	
Document Name	

Comment

NRG agrees with the EPSA comments.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5,6

Answer	
Document Name	

Comment

NRG Energy Inc is in support of the comments made by EPSA.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE recommends adding the approval of the Inverter-Based Resource (IBR) definition to the prerequisite actions.

Likes 0	
Dislikes 0	
Response	

3. Provide any additional comments for the Drafting Team to consider, if desired.

Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	

As AEP stated in the previous ballot period, the scope and general intent of PRC-030 appears reasonable, but the process and flow are flawed and need to be changed. The Standard seems to reflect the spirt of the Technical Rationale, but its obligation language doesn't seem to correlate strongly enough with it. While it might be reasonable to simply identify the “event” within 90 days (or 120 days to match PRC-004), additional time will still be needed to research and determine the root cause(s). This could conceivably take 90 days or more, especially if support is needed from the OEM. And once the cause is determined, at least 60 additional days (to match PRC-004) would then be needed to develop the CAP and document the Applicability (R2.1.2) of that CAP to other facilities. Applicability cannot be documented without first determining the root cause and then possibly developing the CAP. It cannot be assumed that a root cause will be found in every case, and the standard needs to allow for this. To further illustrate our concern, the standard drafting team provided this response to AEP comments: “The Drafting Team believes it should be up to the GO to develop a process to identify and analyze events. Requirement R2 makes it clear that they have 90 days from the date of the event to complete analysis, regardless of when the event was identified. They also have 90 days to complete analysis of events identified by the BA, RC, or TOP from the date they were notified of the event.” AEP understands this response, however the revisions to the standard do not match this response. Specifically, “that they have 90 days from the date of the event” is not what is written in R2. R2 presently reads “within 90 calendar days of identifying an active power change event”, which has a different meaning. AEP agrees that it should be measured from the date of the event, not the date of identifying an event. One related gap, as we see it, is that it is not explicitly clear how many days are afforded to identify an event, though 90 days are inferred. These collective concerns are the primary driver behind our decision to vote negative on PRC-030.

The timelines for R1 and R2 are clear for situations when the GO has received a request that identifies a Real Power change pursuant to R1, however the timeline is not clear for those cases when the GO self-identifies. As an example, does “within 90 calendar days of identifying an active Real Power change” mean within 90 days of the event itself? AEP requests that language be added to the requirements which makes the timeline clear for both those instances. Once again, some clarity is provided in the Technical Rationale, however it is not clear within the obligations themselves.

The proposed version of PRC-030 assumes that a root cause will be found in every case, but this is not realistic. The standard must be revised to accommodate for situations where a root cause(s) is never found or identified. The SDT recently stated in their Consideration of Comments response that “If no root cause is found, a GO should work with the RC to explain the details of the performance issues and develop a monitoring plan to capture future events,” however we do not see how industry could draw this conclusion from the language currently used.

R2 and R3 include the word “applicable” when referencing the RC, BA, and Transmission Operator, however we believe this word is misleading and may be interpreted inconsistently. As a result, we recommend instead using “associated” which was recently proposed for use in PRC-029-1.

Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE appreciates the effort the drafting team has put into drafting these standards. Texas RE has the following comments on PRC-030-1:

In Requirement R1, it seems that the fourth bulleted exclusion would be better suited to be included under Requirement R3. If the reduction in Real Power meeting the appropriate threshold MW is due to a Protection System Misoperation, it would not be immediately evident in real-time, if. This will become evident during performance analysis and can be used as a technical justification that address why corrective actions will not be implemented. Texas RE recommends removing the fourth bullet from Requirement R1 and adding it to Requirement R3. Please see below (in bold):

R3. If performance issues and a need for corrective actions were identified in Requirement R2 Part 2.1.3, each applicable Generator Owner shall, within 60 calendar days of completing the analysis in Requirement R2, develop one of the following and provide it to the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

- A Corrective Action Plan (CAP) for the identified inverter-based resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R2 Part 2.1.3; or
- A technical justification that addresses why corrective actions will not be implemented; or
- **Analysis concluded that the Real Power reduction was due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.**

Texas RE noticed in Requirement R2, in the first line, “an” should be changed to “a” since it is referring to Real Power, not active.

Texas RE previously commented Requirement R2, subpart 2.2 seems to require that an additional request be made by the RC, BA, or TOP for the analysis results. Texas RE recommends the phrase “upon request” be removed from subpart 2.2 because Requirement R2 language already includes the ‘request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator’. Please see the revision below (in bold).

Suggestion:

2.2. **Upon request, p**rovide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator

Texas RE recommends Requirement R4 include a timeframe for implementing the Corrective Action Plans. It is essential to implement the CAPs as quickly as practicable to improve the system reliability and risk mitigation. Texas RE recommends the following (in bold):

R4. Each applicable Generator Owner shall, for each of its Corrective Action Plans developed pursuant to Requirement R3 **within 120 days or sooner**:

Technical Rationale - Figure 1.2: Texas RE recommends adding a line from Mitigate (R3) box to a new box “Notification to RC, BA, TOP” to match Requirement R3 language.

Technical Rationale - Figure 1.3: Texas RE recommends adding clarification on the chart to note that the blue line and above is the threshold for meeting the R1 MW criteria, which is greater than or equal to 10%.

Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	
Document Name	
Comment	

R2. Data quality concern in an event happening in 4 seconds and being able to complete the analysis.

Concerns with having to provide the information to multiple entities.

R3 & R4. The reporting requirement should be synchronized with R3 and R4. Corrective plans should be intended for internal use only and not necessary to be reported out to other entities. What is the need and useability of that information to those entities?

The action to create the Corrective Action Plan should 90 days instead of 60 days. Recommend adding language in R3 that states that if all actions are completed during the analysis phase to correct the issue there will be no need for a CAP.

Likes 0	
Dislikes 0	

Response

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

FirstEnergy requests the DT clarify how to ensure cause for changes that are at least 20MW and at least 10% of gross nameplate under the first bullet point for R1 is related to equipment's components rather than issues outside of the control of the GO.

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

The standard's Applicability, as indicated in section 4.2, increased from just BES to now include non-BES > 20 MVA. What authority does NERC have, at present, to place requirements on non-BES (and, probably, non-registered) generators? NERC should not be decreeing what the design of non-BES resources should be or have standards that apply to them.

We continue our objection to the R3 requirement that the GO has to provide CAP information from Requirement R2.1.3 to the applicable RC, BA, and TOp if they haven't asked for it. The RC, BA, and TOp may have hundreds of sites that they oversee and work with and having to receive info that they may not need (or even want) places an unnecessary burden on them. Also, having to provide this info, that the RC, BA, or TOp many not need/want, places an undue burden on the GO. If the RC, BA, or TOp need/want this info, let them ask for it individually, or let them put the requirement to submit it to them in their data specifications per TOP-003 and/or IRO-010. Same comment for R4.3.

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 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 that is unclear.

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 Steffensen - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	

R1. This requires utilities to identify outages on IBR systems "occurring within a 4 second period". Idaho Power Company (IPC) has several clarifying questions: What does this mean? What 4 second period is being specified here? Does this mean outages less than 4 seconds are not included or does this mean the 4 second period outages are the only ones counted? Alternatively, does this mean that the utility must identify the outage within 4 seconds? IPC feels clarification would be helpful.

R2. The utility is responsible for meeting compliance with Requirement R2.1 (and its subparts) within 90 calendar days; however, IPC wants to emphasize that the manufacturers perform this roots cause analysis. As a result, the utility is dependent on the manufacturer meeting this date, or the utility will be out of compliance. Based on prior experience, this can create challenges in meeting the required 90-day timeline. It should also be noted that some problems are very complicated and root causes take time to develop. There should be additional leniency integrated to account for the time required by third parties to fulfill these requests on behalf of the utilities.

Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,5,6 - WECC	
Answer	
Document Name	09 - RhodesM - IBR Oscillation Event Report_July 2024.pdf
Comment	

BPA identified that both drafts for PRC-028 and PRC-029 include the new IBR definition in the 'new terms' section. BPA recommends the SDT include the same language in PRC-030-1 for continuity.

BPA recommends including in the 'New Terms' section:

Term(s): The terms Inverter-Based Resource (IBR) refer 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 Inverter-Based Resource is: N/A 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.

Additionally, BPA recognizes there are growing instances of system oscillations associated with batteries and their metering systems. For awareness, please see the attached IBR Oscillation Event Report for specificity regarding emerging issues. This document was presented at the WECC combined RRC/RAC held July 10, 2024."

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	
Document Name	

Comment

AZPS supports the following comments submitted by EEI on behalf of its members:

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

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

• Suggest modifying PRC-030-1 R2 to 120 calendar days to align with PRC-004 R1-2 120-day investigation and analysis period.

• Duke Energy agrees with and supports the following EEI comment:

“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.” Rephrase sentence to remove or clarify intent of this phrase.

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-030-1 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-030-1 (and PRC-029-1) 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-030-1 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.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

1. We believe the proposed Reliability Standard should be better aligned with the original directive. Requirement R1 should be replaced with a requirement to provide operational data, including actual ramp rates, within 15 calendar days of a request received from an IBR's Reliability Coordinator, Transmission Operator, or Balancing Authority.

2. We believe Requirement R2 has two separate analytical processes combined as one. The first analysis should be like the approach taken in NERC Reliability Standard PRC-004-6 which first confirms the cause of a BES interrupting device operation was from a Misoperation of its Protection System components. In the initial PRC-030-1 analysis and upon notification from a reliability transmission entity, the Generator Owner should confirm no IBR facility performance issues were noted that caused a rapid change in IBR Real Power output. The results of this analysis, including the cause of the change in IBR Real Power output, should then be provided to the Requirement R1 requester (i.e., IBR's Reliability Coordinator, Transmission Operator, or Balancing Authority) within 90 calendar days. If the Generator Owner has confirmed the occurrence of an IBR facility performance issue, then a Corrective Action Plan would be generated under Requirement R3.

3. We believe Requirement R3 should be rewritten to align with the approach taken in NERC Reliability Standard PRC-004-6. Under that Reliability Standard, the entity generates a Corrective Action Plan (CAP) for the identified Protection System component(s) and conducts an evaluation of the CAP's applicability to the entity's other Protection Systems, including other locations. This would replace the second-half portions of the SDT's combined analytical process currently proposed under Requirement R2 and that we suggested removed from the requirement.

4. As proposed, Requirement R4 requires the Generator Owner to provide Corrective Action Plan updates only to the Reliability Coordinator. We believe these updates should be provided to the initial requesting party. Under Requirement R1, that could be a Transmission Operator or a Balancing Authority, as well as a Reliability Coordinator.

5. Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	

Document Name	
Comment	
N/A	
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	
Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	
Document Name	
Comment	
-	
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	MRO-NSRF_2023-02_PRC-030_UFC_07-03-2024_DRAFT.docx

Comment

The MRO NSRF does not believe that the proposed changes in the thresholds are sufficient.

Requirement R1, as proposed, focuses on changes in active power output, less a few scenarios, which was not the intention of the SAR.

Pursuant to the SAR (emphasis added), § Requested Information, ¶2, “IBRs to ensure that any unexpected ceasing of current injection (partial or full) is analyzed by the applicable Generator Owner and mitigated to the extent possible. NERC has also highlighted that many Generator Owners are not aware of these trips and that the Balancing Authority or Reliability Coordinator may often identify the unexpected or unwarranted tripping issues.”

From the excerpt above it is clear that the proposed standard should focus on trips not caused by balance of plant (BOP) Protection Systems, but trips of the individual generating units. As such, the proposed Requirement R1 language needs to focus on generation resource capability, which is based on availability of individual generating units multiplied by the of individual generating unit’s nameplate. For example, consider a wind generation resource with a 100MW aggregate gross nameplate that consists of 50 2MW individual generating units. When the wind generation resource is at 100% availability, then its capability would be 100MW, regardless of fuel supply. If the wind generation resource had 25 individual generating units trip in a short period of time (≤ 1 minute), the new capability of the wind generation resource is now 50MW. The intention of the SAR was for Generator Owners to analyze these types of events (individual generating unit trips) to determine if performance issues exist, not any change in active power output.

It is not reasonable or practicable to have Generator Owners analyze every change in active power output even with the exclusions outlined in the proposed requirement. The MRO NSRF strongly encourages the SDT to consider the process that will be required to demonstrate compliance with the proposed Requirement R1 and the amount of administration that will be required to verify whether a change in active power meets the criteria for analysis in the Proposed Requirement R1.

An additional concern the MRO NSRF has with the four second time frame is that BAL-005-1 R1 specifies a design scan rate of no more than six seconds for acquiring data necessary for calculating ACE and sending to the BA. That is really the defining time frame that is used to setup EMS systems to query BES RTU data. In addition, other entities could have longer scan rates up to 6 seconds. This is also dependent on the communications path and bandwidth available from EMS to the RTU. If a channel has multiple RTU connections on it, then the scan time can vary as it has to be tuned to be able to respond successfully given the bandwidth available to the multiple RTUs on the channel. The MRO NSRF believes that four seconds may be unachievable for some entities and it seems like the four second time should consider BAL-005-1 and an the amount active power changes that occur at an IBR. The MRO NSRF does not believe that amount of precision can actually be achieved the way EMS systems are communicating with BA/RCs today unless some other monitoring mechanism is used.

As such, the MRO NSRF suggest using a 20% change in capability over a one-minute time period to be the threshold for Requirement R1.

· §4. Applicability

The MRO NSRF reiterates its recommendation that the SDT add exclusions to the applicability section of the proposed standard to ensure that PRC-030 R1 does not include balance of plant (BOP) Protection Systems already covered under PRC-004-6. An example would be PV & wind generation 34.5kV collection system Protection Systems. As the proposed standard is currently drafted there is no clear distinguishing language. It is suggested that the footnote information be included in the §4. Applicability to eliminate the footnote altogether.

· Requirement R1:

The MRO NSRF would like to reiterate that Requirement R1 “documented process to identify unexpected changes” is not a requirement within the SAR’s scope. According to the SAR, Generator Owners need to “analyze performance issues identified at their facilities”. Having a documented process is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit.

In R1, suggest the deletion of the word “documented”

In M1, suggest that item 1 be changed from “(1) the documented process...” to “(1) implementation of a process for...”.

With the two changes above deleting “documented”, suggest that item (2) in M1 be deleted.

· Requirement R2:

The MRO NSRF does not agree with allowing the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA) to be able to request an analysis of any a change in “the inverter-based resource(s) active power output”; the criteria for this analysis shall be the same criteria as outlined in Requirement R1.

The MRO NSRF does not agree with the 90 calendar day timeframe and believes it should be 120 days similar to PRC-004-6.

In the new R2.1.3, suggest changing the word “needed” to “indicated” to take into account the possibility of there being no changes available to affect the response of the IBR controls to the system disturbance.

· Requirement R3:

The MRO NSRF would like to reiterate that being required to provide either a ‘Corrective Action Plan or justification of why corrective actions will not be applied to the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA)’ is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit, if the RC, BA & TOP do not need or want this data & analysis.

· Requirement R4.3:

The MRO NSRF would like to reiterate that the proposed Requirement R4.3 is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit, if the RC, does not need or want this information.

· Requirement R1 & R2

The MRO NSRF would also like to reiterate that most inverter based resources are owned by independent power producers (IPP), as such, it is their best interest to ensure a high availability of the Facility and analyses such as the ones being proposed in PRC-030 are not only in the interest of reliability, but also in the interest of the IPP so long as the criteria for performing an analysis is reasonable and cost effective. The MRO NSRF appreciates the efforts the Standards Drafting Team has put forth and is suggesting the following criteria for the proposed PRC-030 analysis based on the aforementioned information:

Removal of Requirement R1 in its entirety and combining it with the proposed Requirement R2 as follows:

R2. Each applicable Generator Owner, within 120 calendar days of either a, capability1 change of greater than 20% of the generation Facilities gross capability1 nameplate or following a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a capability1 change of greater than 20% of the generation Facilities gross nameplate capability1, shall, excluding:

· Changes associated with intermittent primary energy source (fuel supply: wind, solar irradiance) availability;

· Resource dispatch, resource ramping, planned outages, or planned resource testing; or

· Loss of Transmission Provider’s interconnection facilities.

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in capability1;

2.1.2. Document the Facility's Ride-through performance including reactive power response during the event;

2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the susceptibility of its other inverter-based resource facilities to similar events.

2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator.

1: A generation resource capability is based on availability of individual generating units that compromise the Facility multiplied by the individual generating unit's nameplate.

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	
Document Name	

Comment

Facilities: 4.2.1. BES inverter-based resources

Consistent with EEI comments, NextEra reccomends removing "elements associated with" from Section 4.2.1

R1

The standard does not provide clarity regarding changes in Real Power output that occur and are restored before a 4 second period. It is unclear whether if corrected within the 4 seconds, the change would need to be collected and reported.

NextEra recommends providing clarity on what is considered a "complete facility loss of output"

NextEra changing language in R1 to "at least 20 MW and at least 20% of the plant's gross nameplate rating". Changing from 10% to 20% as provided in Draft 2 will still provide meaningful data without burdensome reporting.

R3

NextEra raises concerns regarding CAP timeline to resolve within 90 days. Recommend a CAP greater than 90 days.

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

ITC has no comments

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	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	

R1 requirements
The technical rationale states that criteria for triggering analysis were chosen with the intention of screening out “small active power changes” while being low enough to detects events that present a reliability risk. The DT points to 3 studies performed at solar and wind facilities in Texas where wind speed and solar irradiance changes did not result in greater than a 20mw or 10% nameplate rating Real Power output ∆ in a 4 second window. These studies ranged from 1 month to 1 year, and 160MW-500MW nameplate ratings. Many factors can affect both the Real Power output, as well as the Power rate of change for IBR’s, particularly solar, where temperature, latitude, elevation, humidity, asset age, and geographical features, can all impact the effective output and how fast it may change based on disturbances to its energy source. These studies may provide insufficient data to draw wide conclusions about what changes in Real Power output due are likely for a given ∆ across the entire North American footprint, as the data is limited to a relatively narrow geographical location, number of facilities, and timeframe. Region-specific studies with more robust data would inspire confidence these changes do not present an undue burden in the way of nuisance event analysis.

R2 & R3 requirements
The time periods in R2 and R3 should be increased to 120 calendar days to allow time to determine the root cause and develop a Corrective Action Plan, especially if OEM support is required.

The stated rationale for the discrepancy between the PRC-004 analysis requirement of 120 days and the proposed PRC-030 requirement of 90 days is that: “The PRC-004 timeframe accounts for extreme weather events such as hurricanes that may affect a very large number of Protection Systems for a given responsible entity”.   Additionally it is stated that: “The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed”

The same extreme weather events that cause numerous PS operations can, and may even likely occur at the same time that unexpected output events occur for IBRs. Typically, it will be the same teams that analyze both of these types of events.
Furthermore, it is unclear on what basis the SDT has determined that 90 days allows sufficient time to provide thorough IBR response analysis as no evidence is presented. IBR proprietary control systems remain a major obstacle to analysis, and will necessitate communication with external vendors which are not bound by the compliance timeframe requirements of the PRC.

The same issues regarding control systems and external vendors will also exist for developing CAPs.

Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) 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 comment on the proposed 3rd draft of PRC-030-1: • 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.	
Likes 0	
Dislikes 0	
Response	

Romel Aquino - Edison International - Southern California Edison Company - 3

Answer	
Document Name	EEI Near Final Draft Comments _ Project 2023-02 PRC-030 Draft 3 __ Rev 0a _ 8_06_2024.docx
Comment	
See comments submitted by the Edison Eclectic Institute in the attached file	
Likes 0	
Dislikes 0	
Response	

Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
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	

WEC Energy Group does not agree with the 10% and 20 MW threshold. WEC Energy Group is not satisfied with the SDTs response back to WEC Energy Group in regards to 20MW and 10% threshold. The SDT responded that these values were chosen based on other standards having adopted same values. WEC Energy Group SMEs could not find any other standards that reference these values when it comes to IBR sites. Please name few for reference.

The sample data that was evaluated in the technical rationale document is unreasonable. Selecting Texas region for sample data favors the region with consistent irradiance throughout the year so the same conclusion cannot be applied to the whole US geographical region. If the DT considers evaluating different regions, it will come to a conclusion that there are far more occurrences than what was evaluated for Texas and Hawaii regions. In addition, the DT did not present how long it took to filter through to determine if the events meet R1 or not. WEC Energy Group's concern is not with capturing the event but the administrative burden to filter through to determine if the event meets R1 requirement. Having such a small threshold, the number of events being recorded and evaluated will create unnecessary cost with evaluation effort without significant benefit to BES reliability. Based on submitted comments, other entities have same concerns.

The threshold should be increased to at least 20% gross nameplate AND 20MW.

If DT has concern with applying larger threshold to larger sites, perhaps this can be addressed by applying different thresholds based on Nameplate. For example:

- IBR sites with gross nameplate of 300 MVA or less: complete facility loss of output, or changes in active Real Power output that are at least 20 MW and at least 20% of the plant's gross, and, occurring within a 4 second period
- IBR sites with gross nameplate above 300 MVA: complete facility loss of output, or changes in active Real Power output that are at least 20 MW and at least 10% of the plant's gross, and, occurring within a 4 second period

Likes 0	
Dislikes 0	
Response	

Ryan Strom - Ryan Strom On Behalf of: Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; Tom Schmidt, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group	
Answer	
Document Name	
Comment	

Buckeye supports the comments made by ACES:

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.
Thank you for the opportunity to comment.

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	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	

For Requirement R2, 90 days may not be sufficient for determining the root cause analysis when analysis is dependent on information from the Original Equipment Manufacturer (OEM). Southern Company recommends an option to relax the Violation Severity Level if the Geerator Owner (GO) is actively working with the OEM past 90 days to determine the root cause.

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

Colin Chilcoat - Invenergy LLC - 6

Answer	
Document Name	

Comment

Can the drafting team please confirm that bullet 3 under R1 includes any activation of a RAS or SPS? If not, a separate bullet should be added to account for RAS/SPS activation.

Invenergy would like to thank the drafting team for the opportunity to provide comments.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	
Document Name	

Comment	
We support EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	
Document Name	
Comment	

Can the drafting team please confirm that bullet 3 under R1 includes any activation of a RAS or SPS? If not, a separate bullet should be added to account for RAS/SPS activation.

Invenergy would like to thank the drafting team for the opportunity to provide comments.

Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
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 2020-06 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.

Thank you for the opportunity to 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	
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.

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 its comments on the preceding posting of this standard, the ISO/RTO Council (IRC) Standards Review Committee (SRC) requested that the reporting requirement in Requirement R2 be expanded to include a report to the RC, BA, TO within three business days of the identification of an event. The SRC reiterates that request here. Although a GO/GOP may not have had adequate time to fully assess and analyze the incident at that point, the degree of the unexpected operation may pose significant risk that an operator may need to be aware of for situational awareness. The operator may have seen an impact on the system that could not be explained without this information. A follow-up report when the incident is fully assessed would still be communicated to the operator(s) for any longer-term considerations.

Also, since “IBR Unit” is not currently proposed to be defined term and Part 4.2.1 of the Applicability section of PRC-030 references “element” data, it is important for the standard to require retention of specific IBR unit information as the applicability of PRC-030 is only down to the “common point of connection” and may not identify specific elements.

Footnote: ERCOT is a party to these comments however does not support the above statement regarding Part 4.2.1.

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 does not oppose it, however modifications are needed.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	
Document Name	

Comment

No additional comments

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

Except where noted in those comments, ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own.

In addition, while ERCOT appreciates the modifications to the Requirement R1 criteria, ERCOT would support modifying the criteria to 20 MW ***OR*** 10% instead of 20 MW **AND** 10%. Inverters/wind turbines/etc. will typically be 1-3 MW in size (with newer technologies approaching 4-5 MW). 10% of a 500 MW facility would be 50 MW and 10% of a 1,000 MW facility would be 100 MW (both of which are present and growing in new Interconnection queues), which are excessive thresholds. One approach to address this issue would be to set both a floor and a ceiling by establishing a threshold of 20 MW **AND** 10% for IBRs with a nameplate capacity of less than 200 MW nameplate and to set a threshold of 20 MW **OR** 10% for IBRs with a nameplate capacity greater than or equal to 200 MW.

ERCOT recommends modifying the third bullet of R1 to be "• A Transmission or collection system loss that***, through normal clearing***, disconnects the IBR generator;" which would better align with the language used in other locations in the standards that describe normal clearing of faults.

Finally, in light of FERC's directives in its *Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification*, and in light of modifications made by the PRC-029 SDT, ERCOT believes that NERC should be a part of the review process for any instances in which a GO does not implement a CAP as provided in the 2nd bullet of Requirement R3. For informational purposes, the pertinent language from FERC's Order is provided below (emphasis added).

33. Under Reliability Standard EOP-012-1, a generator owner could explain in a declaration any "technical, commercial, or operational constraints" that preclude its ability to either implement freeze protection measures or implement corrective action plans. However, Reliability Standard EOP-012-1 ***does not define "technical, commercial, or operational constraints," leaving those terms open to interpretation by each generator owner***. In the February 2023 Order, the Commission approved Reliability Standard EOP-012-1 but ***expressed concern with the uncertainties, ambiguities, and vagueness of the Standard's descriptions of constraints, noting that, without criteria to guide the generator owners or guardrails on what constitutes a legitimate constraint, generator owners may avoid the purpose of the Standard altogether or have declarations without auditable elements***. Thus, the ***Commission directed NERC to address the ambiguity of generator owner-defined declarations by including auditable criteria to ensure that declarations cannot be used to avoid mandatory compliance with the Reliability Standard or obligations in a corrective action plan***.

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.

We support the goals of this standard to analyze and mitigate IBR performance issues; however, the standard as written would require significant analysis of events where IBR facilities respond to grid events *correctly*. This would not be cost effective and not aligned with the intention of the SAR as written. The major driver for this is the trigger criteria defined in Requirement R1. Requirement R1 defines the changes in real power output "occurring within a four-second period." The "within four-second period" characterization may miss controller oscillations, control interactions, and slower active or reactive power responses in the wrong direction than intended. It would also pick up all types of dynamic events of an IBR facility, including events where an IBR facility performs correctly. This would lead to detailed forensic event analysis for almost every type of grid event rather than only those events where abnormal performance occurred.

Providing guidance in Requirement R1 for the trigger of the events of concern is a good practice but limiting the requirement language to specify only one trigger (e.g., the "changes in active power output occurring during a period that is no longer than 4 seconds") to capture any type of unexpected changes with an IBR could result in certain types of events being missed while also capturing many events that don't need to be analyzed (e.g., correct/intended responses of an IBR). The recommendation would be to include a set of event triggers as sub-requirements under Requirement R1.

Example triggers could include:

(1) ***Unexpected*** changes in active or reactive power output within a four-second period

(2) ***Unexpected*** changes in active or reactive power output ***longer*** than a four-second period, including momentary cessation, partial or full IBR tripping, or detailed recovery of active power response post-fault

(3) Active or reactive power oscillations that are poorly damped or persist for longer than *[consider value]* seconds

This structure would give the opportunity for additional triggers to be easily added and implemented/considered to more suitably capture unexpected operations occurring from IBRs on the BPS.

If additional trigger criteria are not used, another approach would be to modify the existing "within four-second window" criteria by adding additional SCADA scan rate samples into the existing trigger. Specifically, this would ensure that correctly performing dynamic events would ***not*** be considered within scope, and rather only significant power output changes that are sustained (i.e., trip of an IBR, active power output jump up/down that remains longer than a dynamic event such as momentary cessation or delayed power recovery, etc.). This would align with the language in the SAR to identify IBRs that incorrectly perform during dynamic grid events by either tripping, reducing active power, and not returning to pre-event output levels within 1-second.

Example criteria language for Requirement R1 along these lines could be:

"Changes in active power output that are the greater of either 10% of the plant's gross nameplate

rating, or 20 MW, and the change in real power output remains at the new value for two or more consecutive SCADA scan rates [or could say remains at the new value for 2 seconds or longer]."

In addition, the drafting team should consider modifying Requirement R1 and Requirement R2 so that changes in power output are not limited to just real power, but also reactive power. In fact, Requirement 2.1.2 highlights documentation a facility's ride-through performance including reactive power responses during grid events.

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:	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues | Draft 3
Comment Period Start Date:	7/22/2024
Comment Period End Date:	8/12/2024
Associated Ballot(s):	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Implementation Plan AB 3 OT 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues PRC-030-1 AB 3 ST

There were 60 sets of responses, including comments from approximately 151 different people from approximately 105 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) 446-2564.

Questions

1. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

2. Does the entity have any concerns regarding the 2023-02 Implementation Plan? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

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 Performance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Corporation (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
					Greg Campoli	NYISO	1	NPCC

					Matt Goldberg	ISO New England	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Elizabeth Davis	PJM	2	RF
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
					Jolly Hayden	East Texas Electric Cooperative, Inc.	NA - Not Applicable	Texas RE
					Scott Brame	North Carolina Electric	3,4,5	SERC

						Membership Corporation		
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Amber Skillern	East Kentucky Power Cooperative	1	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	3	SERC

						Power Company		
					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
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	6	NPCC

						Resources, Inc.		
					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
Ryan Strom	Ryan Strom		RF	Buckeye Power Group	Carl Spaetzel	Buckeye Power, Inc.	3	RF
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Kevin Zemanek	Buckeye Power, Inc.	5	RF
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. hold Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy supports the scope of this standard and finds no alternatives or more cost-effective options for consideration.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	

Answer	No
Document Name	
Comment	
Revisit PRC-030-2 Standard within 2-years to allow applicable personnel cognizant of its capabilities to be better prepared to recognize cost-effective options or recommendations to answer this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
Avista agrees with EEI Comments	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see response to EEI comments.	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI has no suggested alternatives over what has been proposed within PRC-030-1.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
"See EEI Comments"	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI comments.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
We concur with EEI's comments.	
Likes 0	
Dislikes 0	

Response	
Please see response to EEI comments.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPC has signed on to ACES comments:

It is the opinion of ACES that PRC-030-1 Requirement R1 should be more aligned with PRC-004-6 Requirement R1. In short, we believe that requiring a documented process to identify applicable events at an IBR, as is currently required by PRC-030-1 R1, increases the compliance burden for the GO with no appreciable decrease in the risk to the BPS. Therefore, we recommend striking the phrase “implement a documented process to” from PRC-030-1 Requirement R1. The revised version of R1 would thus read as follows:

R1. Each applicable Generator Owner shall 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 4 second period. 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 IBR generator; or

• Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.

Secondly, ACES does not agree with the RC, BA, or TOP being able to require the GO to perform an analysis of any event type chosen by the RC, BA, or TOP. We believe that the event types identified by the RC, BA, or TOP should be in line with the event types identified by the GO in R1. Thus, we recommend modifying Requirement R2 as follows:

R2. Each applicable Generator Owner shall perform the activities identified in each subpart of this Requirement, within 120 calendar days, of either:

• identifying a Real Power change event pursuant to Requirement R1 or,

• receiving a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator wherein the requesting entity identified an event meeting the thresholds established in Requirement R1

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in Real Power output;

2.1.2. Document the facility's Ride-through performance including Reactive Power response during the event;

2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities.

2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator.

Furthermore, it is the opinion of ACES that the GO should not be required to submit a CAP to the RC, BA, nor TOP. This is not in line with the requirements identified in PRC-004-6 Requirement R6 nor does it add any appreciable reduction in risk while at the same time increasing the compliance burden for the GO and possibly the RC, BA, and/or TOP. In other words, why should the GO submit its CAP to these entities if they are not required to perform any action(s) upon receipt?

Lastly, requirements R3 and R4 of the proposed PRC-030-1 do not align with one another. For example, as written, R3 requires a CAP be provided to the RC, BA, and TOP whereas R4 Part 4.3 only requires that the RC be notified. We recommend removing the any portion of these requirements that require the GO to submit a CAP to the RC, BA, and/or TOP.

Likes 0	
Dislikes 0	
Response	
Thank you for the comment please see the response to ACES's comment.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
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	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
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	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the 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	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	

Answer	Yes
Document Name	
Comment	
SMEs responded with the following comments: • "Although this is a better version than the previous draft, and it more specifically gets to the root of what the need is, this standard is still an extension of MOD-033 and PRC-002, and now also PRC-004. There does not seem to be enough justification to add a separate standard (and the additional personnel hours required to fulfill it) when the effects could likely be accomplished by updating existing standards."	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The SAR authorized the drafting team to introduce a new standard and the DT decided that a new standard would provide the greatest benefit to reliability.	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
A more cost-effective way would be to let the Transmission Operator identify the events for which service data needs to be studied. Have the Generation Plants responsible for providing that data. Evaluating all potential events results in more work that may or may not provide benefit to the Bulk Power System.	
Likes 0	
Dislikes 0	
Response	

The purpose of the SAR for Project 2023-02 is to have GOs self-identify events and investigate performance, the DT felt this is the best course forward to ensure reliability.	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	Yes
Document Name	
Comment	
“Although this is a better version than the previous draft, and it more specifically gets to the root of what the need is, this standard is still an extension of MOD-033 and PRC-002, and now also PRC-004. There does not seem to be enough justification to add a separate standard (and the additional personnel hours required to fulfill it) when the effects could likely be accomplished by updating existing standards.”	
Likes 0	
Dislikes 0	
Response	
The purpose of the SAR for Project 2023-02 is to have GOs self-identify events and investigate performance, the DT felt this is the best course forward to ensure reliability.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Tri-State agrees with the comments provided by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Please see response to MRO NSRF comments.	
Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
1. We believe the original directive extracted from the last sentence of Paragraph 208 of FERC Order No. 901 has been taken out of context. According to Paragraph 208, as identified by the Standards Drafting Team (SDT) as the purpose for the proposed NERC Reliability Standard PRC-030-1, the Commission directed NERC to develop a “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. The proposed Reliability Standards must account for the technical differences between registered IBRs and synchronous generation resources, such as registered IBRs’ faster control capability to ramp power output down or up when capacity is available. Further, the Reliability Standards must require generator owners to communicate to the relevant planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities the actual post-disturbance ramp rates and the ramp rates to meet expected dispatch levels (i.e., generation-load balance).” It should be noted that most of this paragraph is currently being addressed under NERC Standard Development Project2020-02, Modifications to PRC-024 (Generator Ride-through). If the purpose of NERC Reliability Standard PRC-030-1 is to require Generator Owners to communicate the actual post-disturbance ramp rates and the ramp rates to meet expected dispatch levels and provide that information to other entities, we believe a simpler approach could be taken. 2. For instance, there are already data provisions requirements under NERC Reliability Standard MOD-032-1, IRO-010-5, and TOP-003-5 for entities to include in their data specifications to “request” data like ramp rates to meet expected dispatch levels from Generator Owners. Hence, NERC Reliability Standard PRC-030-1 should be condensed to only provide actual ramp rate (operational) data following a Disturbance. This is like the data request concepts listed within the proposed NERC Reliability Standard PRC-028-1. In that Standard, data is provided to a requested entity based on an observed exception to normal operations. As currently proposed, the Generator Owner has as little 15 calendar days to provide data over a 20-calendar day period. We believe a similar approach should be followed in NERC Reliability Standard PRC-030-1 and allow the Generator Owner 15 calendar days to work with their Generator Operator to collect operational data, including actual ramp rates, that were recorded during a period before, during, and after a Disturbance.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment, DT believes that this requirement fulfills the FERC directive by ensuring the communication between the Balancing Authority, Reliability Coordinator, and Transmission Operator, along with ensuring analysis of Ride Through Criteria.	
Michael Goggin - Grid Strategies LLC - 5	
Answer	Yes
Document Name	
Comment	

We are highly concerned that, relative to the first draft, the current draft of the standard reduces the threshold for output change events that must be reviewed to determine if they need to be analyzed. The revised standard sets the threshold at a change in output that is greater than 10% of the plant's nameplate rating (and greater than 20 MW) within 4 seconds, relative to the threshold of 20% within 2 seconds in the initial draft. This change only adds to our concerns about the generator owner's burden of manually reviewing each output change to exclude events caused by normal fluctuations in plant output due to weather, dispatch, and other factors. No mechanism exists for generator owners to automatically exclude those permissible changes from consideration. Wind and solar plants have a limited number of meteorological towers and pyranometers for measuring the available wind and solar resource, respectively, which makes it difficult in many cases to precisely determine whether changes in output across a plant were caused by resource availability.

The new lower threshold will pick up many more such events, as changes of 10% output within 4 seconds can routinely occur at solar and wind plants. As we explained in our previous comments, the passage of clouds over medium-sized solar plants can cause changes in output that are larger than this threshold.[1] As a result, in some cases a large share of the events a generator owner is required to review will be these normal changes in output, diverting their time and resources away from addressing real reliability concerns.

The drafting team's response to our comments in the first round of balloting only reinforces our concern about the burden imposed on the generator owner: "GOs would not know if it was unexpected behavior of generator settings and controls until the analysis is performed. The exceptions that have been moved from the footnote to the Standard Language allow for GOs to dismiss events due to cloud cover, change in wind speed. etc. Outage/Fault codes would be reviewed during the analysis process. It will be up to GOs to develop a process to identify events that that do not fit into the listed exclusions and require further analysis." It is highly burdensome for a generator owner to pull turbine- or inverter-level fault codes and plant-level fault codes for each event with a more than 10% change in output. Moreover, the drafting team cannot ignore the excessive and unworkable burden imposed on generator owners by simply dismissing that with "It will be up to GOs to develop a process to identify events that that do not fit into the listed exclusions and require further analysis."

As explained in our answer to question 2 below, the best solution to these concerns may be to remove most if not all of R1, and instead rely on analysis requests initiated by the Reliability Coordinator, Balancing Authority, or Transmission Operator following a disturbance event that causes a drop in generator output per R2.

Second, we are concerned that generator owners will be required to conduct a full analysis of all events in which an IBR plant reduces real power output to prioritize reactive power output, as is desirable and expected during voltage disturbances. The standard should be revised to include a mechanism to automatically screen out disturbance events in which the IBR generator briefly reduced real power output because it entered reactive power priority mode.

During a voltage disturbance on the bulk power system, the most helpful response is typically for generators to shift some of their power output from providing real power to prioritizing reactive power to help prevent voltage collapse.[2] As experts at the Energy Systems Integration Group (ESIG) explain, summarizing the conclusions of a recent workshop on generator interconnection, "If too much active power is injected into a point of interconnection with already depressed voltage, it may further collapse the voltage, causing more cascading outages and compromising the reliability of the grid. Rather than keeping the active power of an IBR at a pre-disturbance level, it is more beneficial to reduce active power, depending on severity of voltage drop thus preventing further voltage collapse — while reactive power is prioritized and increased to support grid and terminal voltage."[3]

Not only does a requirement to maintain active power production instead of prioritizing reactive power production during a voltage disturbance risk exacerbating voltage collapse, but it is also infeasible in many cases. If the voltage is low during and following a disturbance, even if an IBR plant continues to inject its full pre-disturbance level of active current, it cannot maintain the level of active power it was delivering because voltage is now lower and active power is the product of voltage and current. Moreover, to increase reactive power injection, a generator must typically shift its output away from active power injection (power is comprised of active and reactive components). Both synchronous and asynchronous generators have a finite ability to produce power, so they must reduce real power (P) production to increase reactive power (Q) along the P-Q generator capability curve. In most cases, it is infeasible for any type of generator to maintain active power production while also increasing reactive power output during a disturbance.

Solutions

To address the concerns expressed in our answer to question 1 above regarding the burden on generators of screening out changes in output that are not caused by disturbances, the best solution may be to remove most if not all of R1, and instead rely on analysis requests initiated by the Reliability Coordinator, Balancing Authority, or Transmission Operator following a disturbance event per R2. This would remove the inefficient “needle in the haystack” burden on generators under R1 to screen every output change event to find the small subset that are due to disturbances, and instead only focus resources on reviewing significant disturbance events that coincided with a change in generator output. Because many generators do not have synchrophasors or other equipment required to determine when significant grid disturbances have occurred, it makes more sense for the analysis to be initiated by a request from the RC, BA, or TO. Relatedly, we reiterate our request from the first comment period to add a requirement to R2 that the RC, BA, or TO must file its request within 15 days of the disturbance event. This will ensure that the GO has at least five days to pull data before it is overwritten, given that the data retention period in the current draft of PRC-028 R7 is 20 days.

As explained above, the standard should also be revised to include a mechanism to exclude analysis of disturbance events in which the IBR generator briefly reduced real power output because it entered reactive power priority mode.

Finally, the requirement on the generator owner in 2.1.4 to “Determine the applicability of the root cause(s) to the Generator Owner’s other Inverter-Based Resource facilities” appears to be unreasonable if not unworkable. A company that owns multiple IBR plants typically uses different equipment and settings across its plants, and some may be wind plants while others are solar plants, so there is no reason to assume its other plants have the same susceptibility simply because they have the same owner. At minimum, the requirement should be clarified to specify whether projects owned by the same parent company but that are incorporated as separate LLCs must be assessed as part of compliance with 2.1.4., and other such details.

If PRC-30 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, these changes would help to secure sufficient support for the standard to pass during re-balloting.

{C}[1]{C} https://www.sciencedirect.com/science/article/abs/pii/S0306261917300144

{C}[2] https://www.esig.energy/download/interconnection-requirements-need-for-harmonization-jason-macdowell/?wpdmdl=9267&refresh=62f587eab15591660258282, at 6

{C}[3]{C} https://www.esig.energy/wp-content/uploads/2022/10/Joint-Generator-Workshop-Summary-1.pdf, at 29

Likes 0	
Dislikes 0	
Response	
The DT performed an assessment on how frequently the thresholds could be met and included this information in the Technical Rationale. The DT agrees that some data automation will be helpful for screening events. The DT recognizes some expected, proper performance could meet the Requirement R1 thresholds and require further investigation. Capturing some level of false positives is a consequence of most simple screening methods. The DT aimed to balance accuracy, and mitigation of risks in developing the criteria to help further reliability.	
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 Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 1	
Likes 0	
Dislikes 0	
Response	
Please see response to MRO NSRF comments.	
Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	Yes
Document Name	
Comment	

TransAlta supports Entergy's comment: "A more cost-effective way would be to let the Transmission Operator identify the events for which service data needs to be studied. Have the Generation Plants responsible for providing that data. Evaluating all potential events results in more work that may or may not provide benefit to the Bulk Power System."	
Likes 0	
Dislikes 0	
Response	
Please see response to Entergy comments.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF membership is concerned with the time/effort required to perform event identification and post-event performance validation. Even with automation, the process will require Generator Owner (GO) personnel to analyze and identify those IBR facility power change events that require corrective actions. The NAGF members believe that this will impose a significant human capital burden for GO registered entities.	
Likes 0	
Dislikes 0	
Response	
The DT performed an assessment on how frequently the thresholds could be met and included this information in the Technical Rationale. The DT agrees that some data automation will be helpful for screening events.	
Alison MacKellar - Constellation - 5	
Answer	Yes

Document Name	
Comment	
Constellation aligns with the NAGF comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Please see response to NAGF comments.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
The MRO NSRF does not believe that this is cost-effective as currently proposed. Please see the MRO NSRF's other responses to questions. Perhaps determining subsections of the North American electric grid where this detailed monitoring and analysis is most needed rather than requiring it across the entire geographic area. The system stiffness to voltage and frequency fluctuations should be accounted for in regions where the IBR facilities are not likely to be affected by abnormal system condition events. Any possible reduction in the number of facilities required to install this equipment is a direct cost reduction.	
Likes 1	Western Area Power Administration, 1, Hammer Ben
Dislikes 0	
Response	
The expectation is for every plant to operate reliably no matter the region and for each plant to be treated on an equal basis. Thank you for the comment and the DT will take this into consideration.	
Megan Melham - Decatur Energy Center LLC - 5	

Answer	Yes
Document Name	
Comment	

Capital Power supports the NAGF's comments:

The NAGF membership is concerned with the time/effort required to perform event identification and post-event performance validation. Even with automation, the process will require Generator Owner (GO) personnel to analyze and identify those IBR facility power change events that require corrective actions. The NAGF members believe that this will impose a significant human capital burden for GO registered entities.

Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see the response to NAGF's comment.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	

Constellation aligns with NAGF comments.

Kimberly Turco on behalf of Constellation Energy Segments 5 and 6.

Likes 0	
Dislikes 0	
Response	

Please see response to NAGF comments.	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Please see response to MRO NSRF comments.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power supports MRO’s NERC Standards Review Forum’s (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to MRO NSRF comments.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	

Comment	
NERC and FERC should allow PRC-024-3 and PRC-029 to be implemented to allow for corrections/requirements to take place and then evaluate if PRC-030 and its requirements as currently proposed are actually needed.	
Likes 0	
Dislikes 0	
Response	
As indicated by the SAR, recent operational experience (e.g., NERC Disturbance Event Reports) indicates the need for the standard. In addition, PRC-030 is one of the 901 Milestone 2 standards and has been developed in coordination with and to complement the other Milestone 2 standards.	
Ryan Strom - Ryan Strom On Behalf of: Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; Tom Schmidt, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group	
Answer	Yes
Document Name	
Comment	
Buckeye supports the comments made by ACES: It is the opinion of ACES that PRC-030-1 Requirement R1 should be more aligned with PRC-004-6 Requirement R1. In short, we believe that requiring a documented process to identify applicable events at an IBR, as is currently required by PRC-030-1 R1, increases the compliance burden for the GO with no appreciable decrease in the risk to the BPS. Therefore, we recommend striking the phrase “implement a documented process to” from PRC-030-1 Requirement R1. The revised version of R1 would thus read as follows: R1. Each applicable Generator Owner shall 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 4 second period. 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 IBR generator; or
• Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.
Secondly, ACES does not agree with the RC, BA, or TOP being able to require the GO to perform an analysis of any event type chosen by the RC, BA, or TOP. We believe that the event types identified by the RC, BA, or TOP should be in line with the event types identified by the GO in R1. Thus, we recommend modifying Requirement R2 as follows:
R2. Each applicable Generator Owner shall perform the activities identified in each subpart of this Requirement, within 120 calendar days, of either:
• identifying a Real Power change event pursuant to Requirement R1 or,
• receiving a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator wherein the requesting entity identified an event meeting the thresholds established in Requirement R1
2.1. Analyze its IBR facility performance during the event, including:
2.1.1. Determine the root cause(s) of change(s) in Real Power output;

2.1.2. Document the facility's Ride-through performance including Reactive Power response during the event;
2.1.3. Assess any performance issues identified and if corrective actions are needed; and
2.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities.
2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator.
Furthermore, it is the opinion of ACES that the GO should not be required to submit a CAP to the RC, BA, nor TOP. This is not in line with the requirements identified in PRC-004-6 Requirement R6 nor does it add any appreciable reduction in risk while at the same time increasing the compliance burden for the GO and possibly the RC, BA, and/or TOP. In other words, why should the GO submit its CAP to these entities if they are not required to perform any action(s) upon receipt?
Lastly, requirements R3 and R4 of the proposed PRC-030-1 do not align with one another. For example, as written, R3 requires a CAP be provided to the RC, BA, and TOP whereas R4 Part 4.3 only requires that the RC be notified. We recommend removing the any portion of these requirements that require the GO to submit a CAP to the RC, BA, and/or TOP.

Likes 0	
Dislikes 0	

Response

Please see responses to ACES.

Scott Thompson - PNM Resources - 1,3,5 - WECC	
Answer	Yes
Document Name	
Comment	
Please consider the following: **1. Overlap with Existing Standards:** The new standard is seen as an extension of existing standards (MOD-033, PRC-002, PRC-004) and may not justify the additional personnel hours required. **2. Cost-Effectiveness:** A more efficient approach would be for Transmission Operators to identify necessary service data events and have Generation Plants provide the data, rather than evaluating all potential events. **3. Clarification of Directives:** The original directive from FERC Order No. 901 has been taken out of context. The proposed standard should focus on providing actual ramp rate operational data following disturbances. **4. Existing Data Provisions:** There are already data provision requirements under other NERC standards (MOD-032-1, IRO-010-5, TOP-003-5) that could be utilized. **5. Targeted Monitoring:** Detailed monitoring and analysis should be focused on specific sections of the grid where it is most needed, rather than across the entire geographic area, to reduce costs.	
Likes 0	
Dislikes 0	
Response	
Please see responses to MRO NSRF, NAGF, and ACES on these topics.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	

As currently drafted, Invenergy believes PRC-030-1 imposes a significant resource burden on GOs without commensurate benefit to reliability. Considerable amounts of time will be required to identify, analyze, and validate every event involving a power change of the applicable magnitude. As an alternative, the SDT could consider revising R1 to require Generator Owners to analyze events only upon request by the applicable Transmission Operator, Balancing Authority, or Reliability Coordinator. This would allow the Generator Owner to focus its resources and efforts on analyzing events of significance to the BES.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT notes that regional entities will not always have the ability to identify single plant performance issues. Also, the SAR specifically directed the GO to identify performance issues and initiate the analysis.	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	
As currently drafted, Invenergy believes PRC-030-1 imposes a significant resource burden on GOs without commensurate benefit to reliability. Considerable amounts of time will be required to identify, analyze, and validate every event involving a power change of the applicable magnitude. As an alternative, the SDT could consider revising R1 to require Generator Owners to analyze events only upon request by the applicable Transmission Operator, Balancing Authority, or Reliability Coordinator. This would allow the Generator Owner to focus its resources and efforts on analyzing events of significance to the BES.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT notes that regional entities will not always have the ability to identify single plant performance issues. Also, the SAR specifically directed the GO to identify performance issues and initiate the analysis.	

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	

It is the opinion of ACES that PRC-030-1 Requirement R1 should be more aligned with PRC-004-6 Requirement R1. In short, we believe that requiring a documented process to identify applicable events at an IBR, as is currently required by PRC-030-1 R1, increases the compliance burden for the GO with no appreciable decrease in the risk to the BPS. Therefore, we recommend striking the phrase “implement a documented process to” from PRC-030-1 Requirement R1. The revised version of R1 would thus read as follows:

R1. Each applicable Generator Owner shall 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 4 second period. 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 IBR generator; or
- Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.

Secondly, ACES does not agree with the RC, BA, or TOP being able to require the GO to perform an analysis of any event type chosen by the RC, BA, or TOP. We believe that the event types identified by the RC, BA, or TOP should be in line with the event types identified by the GO in R1. Thus, we recommend modifying Requirement R2 as follows:

R2. Each applicable Generator Owner shall perform the activities identified in each subpart of this Requirement, within 120 calendar days, of either:

· identifying a Real Power change event pursuant to Requirement R1 or,

· receiving a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator wherein the requesting entity identified an event meeting the thresholds established in Requirement R1

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in Real Power output;

2.1.2. Document the facility's Ride-through performance including Reactive Power response during the event;

2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities.

2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator.

Furthermore, it is the opinion of ACES that the GO should not be required to submit a CAP to the RC, BA, nor TOP. This is not in line with the requirements identified in PRC-004-6 Requirement R6 nor does it add any appreciable reduction in risk while at the same time increasing the compliance burden for the GO and possibly the RC, BA, and/or TOP. In other words, why should the GO submit its CAP to these entities if they are not required to perform any action(s) upon receipt?

Lastly, requirements R3 and R4 of the proposed PRC-030-1 do not align with one another. For example, as written, R3 requires a CAP be provided to the RC, BA, and TOP whereas R4 Part 4.3 only requires that the RC be notified. We recommend removing the any portion of these requirements that require the GO to submit a CAP to the RC, BA, and/or TOP.

Likes 0	
Dislikes 0	

Response

The DT kept the documented process because it is an important element to ensure a process is in place that could adequately capture events. The documented process can be found in other Reliability Standards such as CIP-003, CIP-004, CIP-005, and PRC-012.

Secondly, thank you for your concerns. The thresholds only catch a subset of events that pose a risk to the system stability, The RC, BA, TOP require the ability to require analysis to other events that pose risks to the system.
In regard to the comment in concerns to submitting a CAP to the RC, BA, TOP.

Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC

Answer	Yes
Document Name	
Comment	
NV Energy agrees with the NSRF comments that the proposed is not a cost-effective solution.	
Likes 0	
Dislikes 0	
Response	
Please see response to NSRF comments.	
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 for the support.	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for the support.	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on alternatives or cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	

Document Name	
Comment	
NRG Energy Inc is in support of the comments made by EPSA.	
Likes 0	
Dislikes 0	
Response	
Please see response to EPSA comments.	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	
Document Name	
Comment	
NRG agrees with the EPSA comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to EPSA comments.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
ITC has no comments	

Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	
Document Name	
Comment	
Ameren has no comment on the cost effectiveness of this project.	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
NCPA understands Ferc Order 901 and does not oppose it. 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. Basically, what we are being asked to do is 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 the comment.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	

2. Does the entity have any concerns regarding the 2023-02 Implementation Plan? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
We support EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI's comment.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
"See EEI Comments"	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI's comment.	

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI has no concerns with the Implementation Plan for PRC-030-1	
Likes 0	
Dislikes 0	
Response	
Thank you for comment and support.	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Please see response to MRO NSRF's comment.	
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	
Please see response to EEI's comment.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
Avista agrees with EEI comments	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI's comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Consider implementing a 2028 implementation date instead of 2027 since most companies have already committed resources relative to bids, etc.; expensive design change requests will be required using the proposed date.	

Likes 0	
Dislikes 0	
Response	

Thank you for the comments, the DT has considered this but to ensure reliability will be continuing with the 2027 year. The DT does not identify requirements in PRC-030 for a GO to provide data it doesn't have at an IBR. Should adequate disturbance monitoring at an IBR be pending installation, any analysis performed by the GO may be limited until such monitoring is installed per PRC-028. Requiring data would coincide with their PRC-028 rollout which is only 50% of facilities by 3 years after approval of PRC-028, and 100% by 2030. The entity would have until 2030 to fully install monitoring equipment, so with PRC-030-1 the timelines should not be limited and restricting implementation.

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	No
Document Name	
Comment	

None

Likes 0	
Dislikes 0	
Response	

Thank you for the comment and support.

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	No
Document Name	
Comment	

Black Hills Corporation has no concern with the Implementation Plan	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy offers no comments toward the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment and support.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,Texas RE,NPCC,SERC,RF, Group Name SRC 2024	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
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	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
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	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment and support.	
Ryan Strom - Ryan Strom On Behalf of: Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; Tom Schmidt, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment and support.	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	

WECC voted yes but offers the following comments/concerns:

PRC-030- Separating the Requirements out by design and operation is not realistic and gives the false appearance of being applicable prior to Jan 1, 2030. The language of the Requirements, as written, are unenforceable from a design perspective for BES IBRs and non-BES IBRs.

Design aspects for the Requirement appear to be as follows (If not DT needs to explicitly explain what the “design” portion of the Requirement language is so that everyone—registered entities, Regions, NERC, and FERC are on the same page) :

R1- Process has to be designed by effective date of Standard for BES IBRs or (later of Jan 1, 2027 or effective date for non-BES IBRs). Effective review of compliance cannot be completed on design as the Requirement language is to “implement” a documented

process. If an entity has not designed the “process”, it seems the entity would be non-compliant, but the Requirement is unenforceable. The process cannot be implemented unless an event occurs which is an operational concern with different timelines. R2 through R4 all depend upon an event occurring. It also appears that R2-R4 would be unenforceable as written, because if R1 was not complied with, R2 would not be enforceable. If R2 was not complied with, R3 would not be doable and if R3 was not complied with, R4 would not be enforceable.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the DT has considered these concerns and revised the IP.	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	Yes
Document Name	
Comment	
Six months after FERC approval is unreasonable to have equipment and procedures in place. Especially considering several entities will need to order and install new monitoring equipment from most likely the same companies. The implementation plan should be the same as PRC028.	
Likes 0	
Dislikes 0	
Response	
Thank you for the concern the team considered your comments and the IP has been revised to provide for the 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, or as otherwise provided for by the applicable governmental authority. The DT believes that keeping the IP aligned with the PRC-029 benefits reliability while balancing risks.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group has a concern with following statements from the Implementation plan: *Bulk-Electric System IBRs: Entities shall comply with the portion of Requirements R1, R2, R3 and R4 relating to the **design** of their BES IBRs to meet the requirements by the effective date of the standard.* Please clarify what is the "**design**" portion of requirements R1, R2, R3 and R4. If the "design" cannot be clarified, then only R1 should be met by the effective date of the standard and R2, R3 and R4 should follow upon implementation of PRC-029. *Performance-Based Elements (all applicable IBRs) Entities shall not be required to comply with the portion of Requirements R1, R2, R3, and R4 relating to the **operation** of IBRs to meet the requirements until the entity has established the required Ride-through capabilities for those IBRs in accordance with the implementation plan for Reliability Standard PRC-029-1.* Please clarify what is the "**operation**" portion of requirements R1, R2, R3 and R4.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the DT considered your comment and made some revisions to the implementation plan.	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	Yes
Document Name	

Comment	
Ameren recommends an 18-month implementation plan to allow sufficient time for entities to develop a plan as well as to procure and install the necessary equipment.	
Likes 0	
Dislikes 0	
Response	
Thank you for the concern the team considered your comments and the IP has been revised to provide for the 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, or as otherwise provided for by the applicable governmental authority. The DT believes that keeping the IP aligned with the PRC-029 benefits reliability while balancing risks.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response to MRO NSRF's comment.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes

Document Name	
Comment	
The implementation period should be increased from 12 months to 36 months to allow for any equipment changes or upgrades needed to comply with the standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for the concern. The team considered your comments and the IP has been revised to provide for the 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, or as otherwise provided for by the applicable governmental authority. The DT believes that keeping the IP aligned with the PRC-029 will benefit reliability while balancing risks.	
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	
Extensive detail is required to clarify between design stages and actual operation for phased-in implementation.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the additional ballot of this standard should address this concern in the updated Implementation Plan.	
Kimberly Turco - Constellation - 6	

Answer	Yes
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 for the comment and support, please see responses to MRO NSRF's comment.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation aligns with the NAGF comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support, please see responses to MRO NSRF's comment.	
Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	

Answer	Yes
Document Name	
Comment	

The implementation plan is unnecessarily convoluted. PRC-030 R1 requires entities to have a documented process, then R2/R3/R4 requires entities to exercise the process which depends on having sufficient SER/FR/DDR equipment installed as per PRC-028. Simply tie the timing of the PRC-030 implementation plan to PRC-028.

Thus, TransAlta proposes to have R1 in place by the effective date of the standard, and R2/R3/R4 in place as the disturbance equipment is installed at the respective IBRs as per PRC-028.

Likes 0	
Dislikes 0	
Response	

Thank you for the comment, the DT considered your comment and clarified the IP. In addition, the DT has worked to coordinate the IPs for the 901 Milestone 2 standards.

Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	
Comment	

1. We believe the removal of NERC Reliability Standard PRC-028-1 from the list of Prerequisite Standard(s) is unnecessary. If a Generator Owner is required to provide operational data from a Disturbance impacting their IBR facility, then recorded measurement data associated with that Disturbance would be critical to any post-disturbance analysis. We believe NERC Reliability Standard PRC-028-1 should be added to the list of Prerequisite Standard(s).
2. 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.

Likes 0	
Dislikes 0	

Response

Thank you for the concern the team considered your comments and the IP has been revised to provide for the 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, or as otherwise provided for by the applicable governmental authority. The DT believes that keeping the IP aligned with the other 901 standards balances risks while benefiting reliability. The DT does not identify requirements in PRC-030 for a GO to provide data it doesn't have at an IBR. Should adequate disturbance monitoring at an IBR be pending installation, any analysis performed by the GO may be limited until such monitoring is installed per PRC-028.

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

SMUD agrees with the comments submitted by Tennessee Valley Authority.

Likes 0	
Dislikes 0	

Response

Please see the response to TVA's comment.

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers

Answer	Yes
Document Name	
Comment	
Vistra supports comments made by Entergy.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see the response to Entergy's comment.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
While we appreciate the change from 6 months to 12 months, this still may not provide enough time for the work to be done considering that the GO may not have the required expertise in-house and, thus, may have to contract the work out to a potentially small number of companies that can do the work. The time it takes to develop a statement of work, issue requests for quotes, obtain the quotes, evaluate the quotes, and issue purchase orders can easily be 6 months. Then the work has to be done by the contractor, reviewed by the GO, any GO comments addressed by the contractor, then re-reviewed by the GO to ensure their comments were addressed, and finally issued by the contractor. Depending on the workload and availability of contractors, getting this done within a possible 6-month timeframe is not necessarily reasonable. We request that the effective date be moved to at least 24 months. The non-BES compliance date of January 1, 2027, only gives 7 months from the assumed potential registration date of May 2026. While currently non-registered GOs could start the design process early, they may not know if they will be required to be registered until closer to the May 2026 deadline and this won't give them enough time to get work done or will potentially require them to do work that is not required (if they wind up not having to register). Suggest moving this date out to January 1, 2028.	

If the IBR operation doesn't have to be changed until the implementation of PRC-029-1, and if the PRC-029-1 gives some number of years to be compliant, which it should, why does the design need to be done within one year to potentially "sit on a shelf" for a few years?	
Likes 0	
Dislikes 0	
Response	
Thank you for the concern the team considered your comments and the IP has been revised to provide for the 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, or as otherwise provided for by the applicable governmental authority. The DT believes that keeping the IP aligned with the PRC-029 balances risks while benefiting reliability. Performance in PRC-029 and PRC- 030 are meant to follow the PRC-028 implementation. One doesn't install monitoring at a facility until 2029, they have until 2029 to demonstrate performance with that data in PRC-029 and PRC-030.	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
This is not a phased in implementation plan. Also, Entergy is concerned that the implementation of PRC-030 is dependent on the implementation of PRC-029 which has not been approved yet. The implementation plan should be 365 days instead of 90 days to allow for any control changes that might be required. A process may need to be added to allow extensions of implementation based on potential supply chain issues.	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment, the reason PRC-029 is a pre requisite is due to the definition of “Ride Through criteria” being used in Requirement R2. This standard should not have any supply chain issues that have a direct impact on PRC-030. The 90 days is for reliability purposes and the DT will continue to keep that as the set time.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP has no objections for the implementation period to be twelve months for purposes of identification, however a separate implementation period needs to be established for those cases where field equipment modifications are necessary for detecting changes to Real Power. This may not be a simple “configuration issue”, as new equipment may be needed to obtain additional data points as it is not explicitly stated in R1 where the measurement needs to be taken. AEP suggests adding text to clarify the measure point as “individually, at each MPT level”, “at the POI”, or some other defined point. AEP recommends that an implementation period of 18 months be allowed instead to accomplish whatever field modifications may be necessary.	
Likes 0	
Dislikes 0	
Response	
Thank you for the concerns and the DT feels that the 12 months aligns with other Milestone 2 projects, along with the correct time period needed for implementation to balance risks and ensure reliability. In addition, the IP has been revised to provide for the 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, or as otherwise provided for by the applicable governmental authority.	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Scott Thompson - PNM Resources - 1,3,5 - WECC	
Answer	
Document Name	
Comment	

Please consider the following:

1. Timeframe for Compliance: While extending the compliance period from 6 to 12 months is appreciated, it may still be insufficient due to the need for contracting out work, which involves a lengthy process. A 24-month period is suggested.

2. Non-BES Compliance Date: The proposed compliance date of January 1, 2027, is too soon after the potential registration date of May 2026. Extending this to January 1, 2028, is recommended.

3. Design Implementation: If PRC-029-1 allows several years for compliance, the design work required within one year may be premature and unnecessary.

4. Prerequisite Standards: The removal of PRC-028-1 from the list of prerequisite standards is seen as unnecessary. Including it would ensure critical data for post-disturbance analysis is available.

5. Coordination of Implementation Plans: NERC should align the implementation plans for related standards to provide a unified set of compliance dates, simplifying tracking for Generator Owners.

6. Simplification of Implementation Plan: The current plan is considered convoluted. It is suggested to tie the timing of PRC-030 implementation to PRC-028, with phased compliance dates

Likes 0	
Dislikes 0	

Response

1. The DT feels 12 months is necessary for reliability reasons and to balance risks.
2. Thank you for the comment. The DT will retain the January 2027 date in coordination with the Milestone 2 projects and the FERC Order No. 901.
3. Thank you for the feedback and concern the DT will take this into consideration.
4. The DT received comments from industry, and DT members that felt that making a prerequisite was not necessary for the PRC-030 when moving forward. The DT felt that PRC-030 in Requirement R1 does not require PRC-028 to be implemented.
5. The DT aligned the IP with PRC-028 and PRC-029. Performance in PRC-029 and PRC- 030 are meant to follow the PRC-028 implementation. One doesn't install monitoring at a facility until 2029, they have until 2029 to demonstrate performance with that data in PRC-029 and PRC-030.
6. PRC-030 is tying the timing with other Milestone two standards, this standard does not require or have any supply chain coordination that PRC-028 faces when implementing so that has been taken into to consideration.

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	
Document Name	

Comment	
ITC has no comments	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	
Document Name	
Comment	
NRG agrees with the EPSA comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see the response to EPSA's comment.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	
Document Name	
Comment	
NRG Energy Inc is in support of the comments made by EPSA.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment, please see the response to EPSA's comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends adding the approval of the Inverter-Based Resource (IBR) definition to the prerequisite actions.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the IBR Definition has been added to as a prerequisite action in the updated Implementation Plan.	

3. Provide any additional comments for the Drafting Team to consider, if desired.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	

As AEP stated in the previous ballot period, the scope and general intent of PRC-030 appears reasonable, but the process and flow are flawed and need to be changed. The Standard seems to reflect the spirit of the Technical Rationale, but its obligation language doesn't seem to correlate strongly enough with it. While it might be reasonable to simply identify the "event" within 90 days (or 120 days to match PRC-004), additional time will still be needed to research and determine the root cause(s). This could conceivably take 90 days or more, especially if support is needed from the OEM. And once the cause is determined, at least 60 additional days (to match PRC-004) would then be needed to develop the CAP and document the Applicability (R2.1.2) of that CAP to other facilities. Applicability cannot be documented without first determining the root cause and then possibly developing the CAP. It cannot be assumed that a root cause will be found in every case, and the standard needs to allow for this. To further illustrate our concern, the standard drafting team provided this response to AEP comments: "The Drafting Team believes it should be up to the GO to develop a process to identify and analyze events. Requirement R2 makes it clear that they have 90 days from the date of the event to complete analysis, regardless of when the event was identified. They also have 90 days to complete analysis of events identified by the BA, RC, or TOP from the date they were notified of the event." AEP understands this response, however the revisions to the standard do not match this response. Specifically, "that they have 90 days from the date of the event" is not what is written in R2. R2 presently reads "within 90 calendar days of identifying an active power change event", which has a different meaning. AEP agrees that it should be measured from the date of the event, not the date of identifying an event. One related gap, as we see it, is that it is not explicitly clear how many days are afforded to identify an event, though 90 days are inferred. These collective concerns are the primary driver behind our decision to vote negative on PRC-030.

The timelines for R1 and R2 are clear for situations when the GO has received a request that identifies a Real Power change pursuant to R1, however the timeline is not clear for those cases when the GO self-identifies. As an example, does "within 90 calendar days of identifying an active Real Power change" mean within 90 days of the event itself? AEP requests that language be added to the requirements which makes the timeline clear for both those instances. Once again, some clarity is provided in the Technical Rationale, however it is not clear within the obligations themselves.

The proposed version of PRC-030 assumes that a root cause will be found in every case, but this is not realistic. The standard must be revised to accommodate for situations where a root cause(s) is never found or identified. The SDT recently stated in their Consideration of Comments response that "If no root cause is found, a GO should work with the RC to explain the details of the performance issues and develop a monitoring plan to capture future events," however we do not see how industry could draw this conclusion from the language currently used. R2 and R3 include the word "applicable" when referencing the RC, BA, and Transmission Operator, however we believe this word is misleading and may be interpreted inconsistently. As a result, we recommend instead using "associated" which was recently proposed for use in PRC-029-1.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. After additional review, the DT has made revisions to clarify that the GO has 90 days to both identify the event and perform analysis on the event. The DT has also changed applicable to associated. In the case where a root cause cannot be identified, this would conclude the analysis portion of Requirement R2. However, mitigating actions should be implemented so that a root cause can be determined for subsequent events, such as correcting inverter logs and insufficient data capture. The DT decided that it will retain the current wording of the PRC-030 to ensure reliability is carried out. In the case where it is not possible to obtain information from the OEM in 90 days, the GO could document that information was requested from the OEM and document the best attempt at a root cause based on what they are able to determine from the information available. The DT believes it is important to include a time requirement. The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The CAP should be written to follow up on data collection that is still in process.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	

Document Name	
Comment	

Texas RE appreciates the effort the drafting team has put into drafting these standards. Texas RE has the following comments on PRC-030-1:

In Requirement R1, it seems that the fourth bulleted exclusion would be better suited to be included under Requirement R3. If the reduction in Real Power meeting the appropriate threshold MW is due to a Protection System Misoperation, it would not be immediately evident in real-time, if. This will become evident during performance analysis and can be used as a technical justification that address why corrective actions will not be implemented. Texas RE recommends removing the fourth bullet from Requirement R1 and adding it to Requirement R3. Please see below (in bold):

R3. If performance issues and a need for corrective actions were identified in Requirement R2 Part 2.1.3, each applicable Generator Owner shall, within 60 calendar days of completing the analysis in Requirement R2, develop one of the following and provide it to the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

- A Corrective Action Plan (CAP) for the identified inverter-based resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R2 Part 2.1.3; or
- A technical justification that addresses why corrective actions will not be implemented; or
- **Analysis concluded that the Real Power reduction was due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.**

Texas RE noticed in Requirement R2, in the first line, “an” should be changed to “a” since it is referring to Real Power, not active.

Texas RE previously commented Requirement R2, subpart 2.2 seems to require that an additional request be made by the RC, BA, or TOP for the analysis results. Texas RE recommends the phrase “upon request” be removed from subpart 2.2 because Requirement R2 language already includes the ‘request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator’. Please see the revision below (in bold).

Suggestion:

2.2. **Upon request, p**rovide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator

Texas RE recommends Requirement R4 include a timeframe for implementing the Corrective Action Plans. It is essential to implement the CAPs as quickly as practicable to improve the system reliability and risk mitigation. Texas RE recommends the following (in bold):

R4. Each applicable Generator Owner shall, for each of its Corrective Action Plans developed pursuant to Requirement R3 **within 120 days or sooner**:

Technical Rationale - Figure 1.2: Texas RE recommends adding a line from Mitigate (R3) box to a new box "Notification to RC, BA, TOP" to match Requirement R3 language.

Technical Rationale - Figure 1.3: Texas RE recommends adding clarification on the chart to note that the blue line and above is the threshold for meeting the R1 MW criteria, which is greater than or equal to 10%.

Likes 0	
Dislikes 0	

Response

1st comment: Thank you for your comment. The DT has retained the existing language because there is no need to go into the analysis phase if the power reduction is due to protection misoperation.
2nd comment: Editorial. Accepted.
3rd comment: There are two different "requests": first a request for analysis, then a request to provide the analysis results. Hence the DT has retained the existing language.
4th comment: See responses to previous similar comments. The time needed to implement a CAP will vary widely between situations; a control change may take only a few days, but a hardware change may take months or longer depending on supply chain, for example.
5th comment: Due to space limitations, notifications are included implicitly in the CAP and technical justification steps.
6th comment: Will make the change as suggested. (Unintentionally omitted in previous version.)

Brian Lindsey - Entergy - 1

Answer	

Document Name	
Comment	
R2. Data quality concern in an event happening in 4 seconds and being able to complete the analysis. Concerns with having to provide the information to multiple entities. R3 & R4. The reporting requirement should be synchronized with R3 and R4. Corrective plans should be intended for internal use only and not necessary to be reported out to other entities. What is the need and useability of that information to those entities? The action to create the Corrective Action Plan should be 90 days instead of 60 days. Recommend adding language in R3 that states that if all actions are completed during the analysis phase to correct the issue there will be no need for a CAP.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments. CAPs need to be submitted to the RC, BA, and TOP because they need to understand what mitigations are taking place to understand the system-level reliability risk. Timeframes have been addressed in previous comment responses. If the issue has already been fixed, then the CAP can just describe what was already done.	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
FirstEnergy requests the DT clarify how to ensure cause for changes that are at least 20MW and at least 10% of gross nameplate under the first bullet point for R1 is related to equipment's components rather than issues outside of the control of the GO.	
Likes 0	
Dislikes 0	
Response	
The 2nd and 3rd exception bullets under Requirement R1 cover reasons for power reduction that are outside the control of the GO.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
The standard's Applicability, as indicated in section 4.2, increased from just BES to now include non-BES > 20 MVA. What authority does NERC have, at present, to place requirements on non-BES (and, probably, non-registered) generators? NERC should not be decreeing what the design of non-BES resources should be or have standards that apply to them. We continue our objection to the R3 requirement that the GO has to provide CAP information from Requirement R2.1.3 to the applicable RC, BA, and TOp if they haven't asked for it. The RC, BA, and TOp may have hundreds of sites that they oversee and work with and having to receive info that they may not need (or even want) places an unnecessary burden on them. Also, having to provide this info, that the RC, BA, or TOp many not need/want, places an undue burden on the GO. If the RC, BA, or TOp need/want this info, let them ask for it individually, or let them put the requirement to submit it to them in their data specifications per TOP-003 and/or IRO-010. Same comment for R4.3.	

Likes 0	
Dislikes 0	
Response	
Please refer to https://www.nerc.com/AboutNERC/RulesOfProcedure/Appendix_3A_SPM_Clean_Mar2019.pdf and https://www.nerc.com/pa/Stand/Pages/Project-2024-01-Rules-of-Procedure-Definitions-Alignment_GO-and-GOP.aspx for information on NERC authority to register non-BES IBRs. CAPs need to be submitted because RC, BA, and TOP because they need to understand what mitigations are taking place to understand the system-level reliability risk.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation 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 that is unclear.	
Likes 0	
Dislikes 0	
Response	
This phrase has been removed.	
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	
See responses to MRO NSRF comments.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
R1. This requires utilities to identify outages on IBR systems “occurring within a 4 second period”. Idaho Power Company (IPC) has several clarifying questions: What does this mean? What 4 second period is being specified here? Does this mean outages less than 4 seconds are not included or does this mean the 4 second period outages are the only ones counted? Alternatively, does this mean that the utility must identify the outage within 4 seconds? IPC feels clarification would be helpful. R2. The utility is responsible for meeting compliance with Requirement R2.1 (and its subparts) within 90 calendar days; however, IPC wants to emphasize that the manufacturers perform this roots cause analysis. As a result, the utility is dependent on the manufacturer meeting this date, or the utility will be out of compliance. Based on prior experience, this can create challenges in meeting the required 90-day timeline. It should also be noted that some problems are very complicated and root causes take time to develop. There should be additional leniency integrated to account for the time required by third parties to fulfill these requests on behalf of the utilities.	
Likes 0	
Dislikes 0	
Response	
The requirement is on the GOs, to clarify. The DT extensively discussed different time windows and decided on four seconds based on the longest SCADA scan rates used. Shorter windows are also permitted. Please also refer to the Technical Rational for justification and explanation of the four-second period including examples.	

Requirement R2 also applies to GOs. In the case where it is not possible to obtain information from the OEM in 90 days, the GO could document that information was requested from the OEM and document the best attempt at a root cause based on what they are able to determine from the information available. The DT believes it is important to include a time requirement. The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The CAP should be written to follow up on data collection that is still in process.	
Cain Braveheart - Bonneville Power Administration - 1,5,6 - WECC	
Answer	
Document Name	09 - RhodesM - IBR Oscillation Event Report_July 2024.pdf
Comment	
BPA identified that both drafts for PRC-028 and PRC-029 include the new IBR definition in the 'new terms' section. BPA recommends the SDT include the same language in PRC-030-1 for continuity. **BPA recommends including in the 'New Terms' section:** Term(s): The terms Inverter-Based Resource (IBR) refer 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 Inverter-Based Resource is: N/A 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. Additionally, BPA recognizes there are growing instances of system oscillations associated with batteries and their metering systems. For awareness, please see the attached IBR Oscillation Event Report for specificity regarding emerging issues. This document was presented at the WECC combined RRC/RAC held July 10, 2024.”	
Likes 0	
Dislikes 0	
Response	
The DT has changed the IP to include the IBR definition in the prerequisite actions. Thank you for your comment and information.	

Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	
Document Name	
Comment	
AZPS supports the following comments submitted by EEI on behalf of its members: 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	
Likes 0	
Dislikes 0	
Response	
Thanks for the comment. The phrase has been removed.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
• Suggest modifying PRC-030-1 R2 to 120 calendar days to align with PRC-004 R1-2 120-day investigation and analysis period. • Duke Energy agrees with and supports the following EEI comment: “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.” Rephrase sentence to remove or clarify intent of this phrase.	
Likes 0	
Dislikes 0	

Response	
The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes. The phrase “The Elements associated with” has been removed.	
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-030-1 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, Applicability 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-030-1 (and PRC-029-1) 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-030-1 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.

Likes 0	
Dislikes 0	

Response

Thank you for the comment, both of these comments have been addressed and changes have been made in the revised PRC-030.	
Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

1. We believe the proposed Reliability Standard should be better aligned with the original directive. Requirement R1 should be replaced with a requirement to provide operational data, including actual ramp rates, within 15 calendar days of a request received from an IBR's Reliability Coordinator, Transmission Operator, or Balancing Authority.

2. We believe Requirement R2 has two separate analytical processes combined as one. The first analysis should be like the approach taken in NERC Reliability Standard PRC-004-6 which first confirms the cause of a BES interrupting device operation was from a Misoperation of its Protection System components. In the initial PRC-030-1 analysis and upon notification from a reliability transmission entity, the Generator Owner should confirm no IBR facility performance issues were noted that caused a rapid change in IBR Real Power output. The results of this analysis, including the cause of the change in IBR Real Power output, should then be provided to the Requirement R1 requester (i.e., IBR's Reliability Coordinator, Transmission Operator, or Balancing Authority) within 90 calendar days. If the Generator Owner has confirmed the occurrence of an IBR facility performance issue, then a Corrective Action Plan would be generated under Requirement R3.

3. We believe Requirement R3 should be rewritten to align with the approach taken in NERC Reliability Standard PRC-004-6. Under that Reliability Standard, the entity generates a Corrective Action Plan (CAP) for the identified Protection System component(s) and conducts an evaluation of the CAP's applicability to the entity's other Protection Systems, including other locations. This would replace the second-half portions of the SDT's combined analytical process currently proposed under Requirement R2 and that we suggested removed from the requirement.

4. As proposed, Requirement R4 requires the Generator Owner to provide Corrective Action Plan updates only to the Reliability Coordinator. We believe these updates should be provided to the initial requesting party. Under Requirement R1, that could be a Transmission Operator or a Balancing Authority, as well as a Reliability Coordinator.

5. Thank you for the opportunity to comment.

Likes 0	

Dislikes 0	
Response	
The DT appreciates the comments, the DT understands the accepted PRC-004 standard for synchronous generation may be a good to carry over these ideas into this standard. The DT has spent time discussing these topics and feels that due to IBR generation being different that the PRC-030 process and standard better mitigates reliability risks and improves reliability with these processes. The DT appreciates the comment but will retain the existing language as the team feels the current language is better for reliability.	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
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	
See responses to MRO and EEI comments.	
Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	
Document Name	
Comment	
-	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
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	

The 20 MW only applies to plants smaller than 200 MW, since the 10% threshold would apply to larger plants.	
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 the support.	
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 the support.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	

Document Name	MRO-NSRF_2023-02_PRC-030_UFC_07-03-2024_DRAFT.docx

Comment

The MRO NSRF does not believe that the proposed changes in the thresholds are sufficient.

Requirement R1, as proposed, focuses on changes in active power output, less a few scenarios, which was not the intention of the SAR.

Pursuant to the SAR (emphasis added), § Requested Information, ¶2, “IBRs to ensure that any unexpected ceasing of current injection (partial or full) is analyzed by the applicable Generator Owner and mitigated to the extent possible. NERC has also highlighted that many Generator Owners are not aware of these trips and that the Balancing Authority or Reliability Coordinator may often identify the unexpected or unwarranted tripping issues.”

From the excerpt above it is clear that the proposed standard should focus on trips not caused by balance of plant (BOP) Protection Systems, but trips of the individual generating units. As such, the proposed Requirement R1 language needs to focus on generation resource capability, which is based on availability of individual generating units multiplied by the of individual generating unit’s nameplate. For example, consider a wind generation resource with a 100MW aggregate gross nameplate that consists of 50 2MW individual generating units. When the wind generation resource is at 100% availability, then its capability would be 100MW, regardless of fuel supply. If the wind generation resource had 25 individual generating units trip in a short period of time (≤ 1 minute), the new capability of the wind generation resource is now 50MW. The intention of the SAR was for Generator Owners to analyze these types of events (individual generating unit trips) to determine if performance issues exist, not any change in active power output.

It is not reasonable or practicable to have Generator Owners analyze every change in active power output even with the exclusions outlined in the proposed requirement. The MRO NSRF strongly encourages the SDT to consider the process that will be required to demonstrate compliance with the proposed Requirement R1 and the amount of administration that will be required to verify whether a change in active power meets the criteria for analysis in the Proposed Requirement R1.

An additional concern the MRO NSRF has with the four second time frame is that BAL-005-1 R1 specifies a design scan rate of no more than six seconds for acquiring data necessary for calculating ACE and sending to the BA. That is really the defining time frame that is used to set up EMS systems to query BES RTU data. In addition, other entities could have longer scan rates up to 6 seconds. This is also dependent on the communications path and bandwidth available from EMS to the RTU. If a channel has multiple RTU connections on it, then the scan time can vary as it has to be tuned to be able to respond successfully given the bandwidth available to the multiple RTUs on the channel. The MRO NSRF believes that four seconds may be unachievable for some entities and it seems like the four second time should consider BAL-005-1 and the amount active power changes that occur at an IBR. The MRO NSRF does not believe that amount of

precision can actually be achieved the way EMS systems are communicating with BA/RCs today unless some other monitoring mechanism is used. As such, the MRO NSRF suggest using a 20% change in capability over a one-minute time period to be the threshold for Requirement R1. · §4. Applicability The MRO NSRF reiterates its recommendation that the SDT add exclusions to the applicability section of the proposed standard to ensure that PRC-030 R1 does not include balance of plant (BOP) Protection Systems already covered under PRC-004-6. An example would be PV & wind generation 34.5kV collection system Protection Systems. As the proposed standard is currently drafted there is no clear distinguishing language. It is suggested that the footnote information be included in the §4. Applicability to eliminate the footnote altogether. · Requirement R1: The MRO NSRF would like to reiterate that Requirement R1 “documented process to identify unexpected changes” is not a requirement within the SAR’s scope. According to the SAR, Generator Owners need to “analyze performance issues identified at their facilities”. Having a documented process is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit. In R1, suggest the deletion of the word “documented” In M1, suggest that item 1 be changed from “(1) the documented process...” to “(1) implementation of a process for...”. With the two changes above deleting “documented”, suggest that item (2) in M1 be deleted. · Requirement R2: The MRO NSRF does not agree with allowing the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA) to be able to request an analysis of any a change in “the inverter-based resource(s) active power output”; the criteria for this analysis shall be the same criteria as outlined in Requirement R1. The MRO NSRF does not agree with the 90 calendar day timeframe and believes it should be 120 days similar to PRC-004-6.

In the new R2.1.3, suggest changing the word “needed” to “indicated” to take into account the possibility of there being no changes available to affect the response of the IBR controls to the system disturbance.

· Requirement R3:

The MRO NSRF would like to reiterate that being required to provide either a ‘Corrective Action Plan or justification of why corrective actions will not be applied to the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA)’ is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit, if the RC, BA & TOP do not need or want this data & analysis.

· Requirement R4.3:

The MRO NSRF would like to reiterate that the proposed Requirement R4.3 is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit, if the RC does not need or want this information.

· Requirement R1 & R2

The MRO NSRF would also like to reiterate that most inverter based resources are owned by independent power producers (IPP), as such, it is their best interest to ensure a high availability of the Facility and analyses such as the ones being proposed in PRC-030 are not only in the interest of reliability, but also in the interest of the IPP so long as the criteria for performing an analysis is reasonable and cost effective. The MRO NSRF appreciates the efforts the Standards Drafting Team has put forth and is suggesting the following criteria for the proposed PRC-030 analysis based on the aforementioned information:

Removal of Requirement R1 in its entirety and combining it with the proposed Requirement R2 as follows:

R2. Each applicable Generator Owner, within 120 calendar days of either a, capability1 change of greater than 20% of the generation Facilities gross capability1 nameplate or following a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a capability1 change of greater than 20% of the generation Facilities gross nameplate capability1, shall, excluding:

· Changes associated with intermittent primary energy source (fuel supply: wind, solar irradiance) availability;

· Resource dispatch, resource ramping, planned outages, or planned resource testing; or

· Loss of Transmission Provider's interconnection facilities. 2.1. Analyze its IBR facility performance during the event, including: 2.1.1. Determine the root cause(s) of change(s) in capability1; 2.1.2. Document the Facility's Ride-through performance including reactive power response during the event; 2.1.3. Assess any performance issues identified and if corrective actions are needed; and 2.1.4. Determine the susceptibility of its other inverter-based resource facilities to similar events. 2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator. 1: A generation resource capability is based on availability of individual generating units that compromise the Facility multiplied by the individual generating unit's nameplate.

Likes 0	
Dislikes 0	

Response
Applying a different threshold based on in-service capacity would make compliance very complicated. The DT has selected a threshold that balances comments from different entities. The comments have been addressed in the previous draft to the extent that the DT feel is feasible in consideration of other comments and technical considerations. The DT has considered these avenues with the standard but feels that to ensure the most reliable standard that the current language is not to be modified with these proposed changes. The BA, RC, TOP DT members of the team feel that these are essential for analysis of an event, and less would be sacrificing reliability.
Richard Vendetti - NextEra Energy - 5

Answer	
Document Name	
Comment	

Facilities: 4.2.1. BES inverter-based resources

Consistent with EEI comments, NextEra recommends removing “elements associated with” from Section 4.2.1

R1

The standard does not provide clarity regarding changes in Real Power output that occur and are restored before a 4 second period. It is unclear whether if corrected within the 4 seconds, the change would need to be collected and reported.

NextEra recommends providing clarity on what is considered a “complete facility loss of output”

NextEra changing language in R1 to “at least 20 MW and at least 20% of the plant's gross nameplate rating”. Changing from 10% to 20% as provided in Draft 2 will still provide meaningful data without burdensome reporting.

R3

NextEra raises concerns regarding CAP timeline to resolve within 90 days. Recommend a CAP greater than 90 days.

Likes 0	
Dislikes 0	

Response

“Elements associated with” has been removed.
Please refer to technical rational for discussion of events occurring and recovering within 4 seconds. The event would not need to be reported as written.

Changing to 20% would allow up to a 100 MW loss for a 500 MW facility to not be analyzed, which presents too much risk to BPS reliability.
The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes. The DT members feel that 90 days ensures reliability and extending that would not ensure reliability.

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	
Document Name	
Comment	
ITC has no comments	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
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 the support.	
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	
Please see response to MRO NSRF comment.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	
R1 requirements The technical rationale states that criteria for triggering analysis were chosen with the intention of screening out “small active power changes” while being low enough to detects events that present a reliability risk. The DT points to 3 studies performed at solar and wind facilities in Texas where wind speed and solar irradiance changes did not result in greater than a 20mw or 10% nameplate rating Real Power output Δ in a 4 second window. These studies ranged from 1 month to 1 year, and 160MW-500MW nameplate ratings. Many factors can affect both the Real Power output, as well as the Power rate of change for IBR’s, particularly solar, where temperature, latitude, elevation, humidity, asset age, and geographical features, can all impact the effective output and how fast it may change based on disturbances to its energy source. These studies may provide insufficient data to draw wide conclusions about what changes in Real Power output due are likely for a given Δ across the entire North American footprint, as the data is limited to a relatively narrow geographical location, number of facilities, and timeframe. Region-specific studies with more robust data would inspire confidence these changes do not present an undue burden in the way of nuisance event analysis. R2 & R3 requirements The time periods in R2 and R3 should be increased to 120 calendar days to allow time to determine the root cause and develop a Corrective Action Plan, especially if OEM support is required.	

The stated rationale for the discrepancy between the PRC-004 analysis requirement of 120 days and the proposed PRC-030 requirement of 90 days is that: “The PRC-004 timeframe accounts for extreme weather events such as hurricanes that may affect a very large number of Protection Systems for a given responsible entity”. Additionally it is stated that: “The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed” The same extreme weather events that cause numerous PS operations can, and may even likely occur at the same time that unexpected output events occur for IBRs. Typically, it will be the same teams that analyze both of these types of events. Furthermore, it is unclear on what basis the SDT has determined that 90 days allows sufficient time to provide thorough IBR response analysis as no evidence is presented. IBR proprietary control systems remain a major obstacle to analysis, and will necessitate communication with external vendors which are not bound by the compliance timeframe requirements of the PRC. The same issues regarding control systems and external vendors will also exist for developing CAPs.	
Likes 0	
Dislikes 0	
Response	
The DT finds the thresholds to be reasonable based on the data, expertise and studies that are available and considering system risk. Note that the TR does include some studies outside ERCOT. The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes. The DT members feel that 90 days ensures reliability and extending that would not ensure reliability. In the case where it is not possible to obtain information from the OEM in 90 days, the GO could document that information was requested from the OEM and document the best attempt at a root cause based on what they are able to determine from the information available. The DT believes it is important to include a time requirement. The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The CAP should be written to follow up on data collection that is still in process.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	

Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
See response to MRO NSRF comment.	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI offers the following additional comment on the proposed 3rd draft of PRC-030-1: • 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.	
Likes 0	
Dislikes 0	
Response	
Thank you for the support, this phrase has been removed.	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	EEI Near Final Draft Comments _ Project 2023-02 PRC-030 Draft 3 __ Rev 0a _ 8_06_2024.docx
Comment	

See comments submitted by the Edison Eclectic Institute in the attached file	
Likes 0	
Dislikes 0	
Response	
See response to EEI.	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
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 the support.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
WEC Energy Group does not agree with the 10% and 20 MW threshold. WEC Energy Group is not satisfied with the SDTs response back to WEC Energy Group in regard to 20MW and 10% threshold. The SDT responded that these values were chosen based on other standards having adopted same values. WEC Energy Group SMEs could not find any other standards that reference these values when it comes to IBR sites. Please name a few for reference.	

The sample data that was evaluated in the technical rationale document is unreasonable. Selecting Texas region for sample data favors the region with consistent irradiance throughout the year so the same conclusion cannot be applied to the whole US geographical region. If the DT considers evaluating different regions, it will come to a conclusion that there are far more occurrences than what was evaluated for Texas and Hawaii regions. In addition, the DT did not present how long it took to filter through to determine if the events meet R1 or not. WEC Energy Group's concern is not with capturing the event but the administrative burden to filter through to determine if the event meets R1 requirement. Having such a small threshold, the number of events being recorded and evaluated will create unnecessary cost with evaluation effort without significant benefit to BES reliability. Based on submitted comments, other entities have same concerns.

The threshold should be increased to at least 20% gross nameplate AND 20MW.

If DT has concern with applying larger threshold to larger sites, perhaps this can be addressed by applying different thresholds based on Nameplate. For example:

- IBR sites with gross nameplate of 300 MVA or less: complete facility loss of output, or changes in active Real Power output that are at least 20 MW and at least 20% of the plant's gross, and, occurring within a 4 second period
- IBR sites with gross nameplate above 300 MVA: complete facility loss of output, or changes in active Real Power output that are at least 20 MW and at least 10% of the plant's gross, and, occurring within a 4 second period

Likes 0	
Dislikes 0	

Response

The DT believes this threshold balances the elimination of smaller events with having the GO pro-actively engaged with reviewing larger events. The DT also drew inspiration for the thresholds values from the most recent ROP, this is also justified in the TR how the team came to the final threshold values for Requirement R1. FINAL - ROP Appendix 3A SPM v5 (nerc.com).
The DT has included the NREL reports included the TR that focus on Solar and Wind reports. This adds variation from other regions aside from the Texas region examples. In addition, the DT reviewed papers published by NREL on Solar PV Variability at Small Timescales and Variability of Wind Power Output, which concludes that change in irradiance and wind working through. The DT is going to retain the same threshold values.

Ryan Strom - Ryan Strom On Behalf of: Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; Tom Schmidt, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group

Answer	

Document Name	
Comment	
Buckeye supports the comments made by ACES: 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. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
See the response to ACES’s comment.	
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 for the comment, please see the response to NPCC's comment.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
For Requirement R2, 90 days may not be sufficient for determining the root cause analysis when analysis is dependent on information from the Original Equipment Manufacturer (OEM). Southern Company recommends an option to relax the Violation Severity Level if the Generator Owner (GO) is actively working with the OEM past 90 days to determine the root cause.	
Likes 0	
Dislikes 0	
Response	
In the case where it is not possible to obtain information from the OEM in 90 days, the GO could document that information was requested from the OEM and document the best attempt at a root cause based on what they are able to determine from the information available. The DT believes it is important to include a time requirement. The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The CAP should be written to follow up on data collection that is still in process. The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The CAP should be written to follow up on data collection that is still in process.	
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 the support and comment.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	
Document Name	
Comment	
Can the drafting team please confirm that bullet 3 under R1 includes any activation of a RAS or SPS? If not, a separate bullet should be added to account for RAS/SPS activation. Invenergy would like to thank the drafting team for the opportunity to provide comments.	
Likes 0	
Dislikes 0	
Response	
Disconnection of an IBR facility due to the activation of a RAS or SPS would be included in the bullet 3 exclusion for events that need to be analyzed in Requirement R2.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	
Document Name	
Comment	
We support EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Please see the response to EEI's comment.	
Rhonda Jones - Invenergy LLC - 5	
Answer	
Document Name	
Comment	
Can the drafting team please confirm that bullet 3 under R1 includes any activation of a RAS or SPS? If not, a separate bullet should be added to account for RAS/SPS activation. Invenergy would like to thank the drafting team for the opportunity to provide comments.	
Likes 0	
Dislikes 0	
Response	
Disconnection of an IBR facility due to the activation of a RAS or SPS would be included in the bullet 3 exclusion for events that need to be analyzed in Requirement R2.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
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 2020-06 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. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Please see the response to ACES's 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	
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.	

Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the “Elements associated with” has been removed from the facilities section in the current PRC-030 standard.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,Texas RE,NPCC,SERC,RF, Group Name SRC 2024	
Answer	
Document Name	
Comment	
In its comments on the preceding posting of this standard, the ISO/RTO Council (IRC) Standards Review Committee (SRC) requested that the reporting requirement in Requirement R2 be expanded to include a report to the RC, BA, TO within three business days of the identification of an event. The SRC reiterates that request here. Although a GO/GOP may not have had adequate time to fully assess and analyze the incident at that point, the degree of the unexpected operation may pose significant risk that an operator may need to be aware of for situational awareness. The operator may have seen an impact on the system that could not be explained without this information. A follow-up report when the incident is fully assessed would still be communicated to the operator(s) for any longer-term considerations. Also, since “IBR Unit” is not currently proposed to be defined term and Part 4.2.1 of the Applicability section of PRC-030 references “element” data, it is important for the standard to require retention of specific IBR unit information as the applicability of PRC-030 is only down to the “common point of connection” and may not identify specific elements. Footnote: ERCOT is a party to these comments however does not support the above statement regarding Part 4.2.1.	
Likes 0	
Dislikes 0	

Response	
The DT considered early notification of performance issues and has chosen not to add an additional requirement on the GO. The DT felt that the exent of the requirement on the GOs was sufficient and adequate when it comes to the action of reporting.	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
NCPA is not registered to vote on this item and does not oppose it, however modifications are needed.	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
No additional comments	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	

Answer	
Document Name	

Comment

Except where noted in those comments, ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own.

In addition, while ERCOT appreciates the modifications to the Requirement R1 criteria, ERCOT would support modifying the criteria to 20 MW ***OR*** 10% instead of 20 MW **AND** 10%. Inverters/wind turbines/etc. will typically be 1-3 MW in size (with newer technologies approaching 4-5 MW). 10% of a 500 MW facility would be 50 MW and 10% of a 1,000 MW facility would be 100 MW (both of which are present and growing in new Interconnection queues), which are excessive thresholds. One approach to address this issue would be to set both a floor and a ceiling by establishing a threshold of 20 MW **AND** 10% for IBRs with a nameplate capacity of less than 200 MW nameplate and to set a threshold of 20 MW **OR** 10% for IBRs with a nameplate capacity greater than or equal to 200 MW.

ERCOT recommends modifying the third bullet of R1 to be “• A Transmission or collection system loss that***, through normal clearing***, disconnects the IBR generator;” which would better align with the language used in other locations in the standards that describe normal clearing of faults.

Finally, in light of FERC’s directives in its *Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification*, and in light of modifications made by the PRC-029 SDT, ERCOT believes that NERC should be a part of the review process for any instances in which a GO does not implement a CAP as provided in the 2nd bullet of Requirement R3. For informational purposes, the pertinent language from FERC’s Order is provided below (emphasis added).

33. Under Reliability Standard EOP-012-1, a generator owner could explain in a declaration any “technical, commercial, or operational constraints” that preclude its ability to either implement freeze protection measures or implement corrective action plans. However, Reliability Standard EOP-012-1 ***does not define “technical, commercial, or operational constraints,” leaving those terms open to interpretation by each generator owner***. In the February 2023 Order, the Commission approved Reliability Standard EOP-012-1 but

expressed concern with the uncertainties, ambiguities, and vagueness of the Standard's descriptions of constraints, noting that, without criteria to guide the generator owners or guardrails on what constitutes a legitimate constraint, generator owners may avoid the purpose of the Standard altogether or have declarations without auditable elements. Thus, the ***Commission directed NERC to address the ambiguity of generator owner-defined declarations by including auditable criteria to ensure that declarations cannot be used to avoid mandatory compliance with the Reliability Standard or obligations in a corrective action plan***.	
Likes 0	
Dislikes 0	
Response	
Please see response to ISO/ RTO council comment. The RC, BA or TOP can request analysis of events outside R1 criteria. The DT determined that at least 20 MW or at least 10% would eliminate smaller events and appropriately balance risks while ensuring reliability. The DT was limited to the parameters of SAR in regard to the EOP-012 comment.	
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. We support the goals of this standard to analyze and mitigate IBR performance issues; however, the standard as written would require significant analysis of events where IBR facilities respond to grid events *correctly*. This would not be cost effective and not aligned with the intention of the SAR as written. The major driver for this is the trigger criteria defined in Requirement R1. Requirement R1 defines the changes in real power output “occurring within a four-second period.” The “within four-second period” characterization may miss controller oscillations, control interactions, and slower active or reactive power responses in the wrong direction than intended. It would	

also pick up all types of dynamic events of an IBR facility, including events where an IBR facility performs correctly. This would lead to detailed forensic event analysis for almost every type of grid event rather than only those events where abnormal performance occurred.

Providing guidance in Requirement R1 for the trigger of the events of concern is a good practice but limiting the requirement language to specify only one trigger (e.g., the "changes in active power output occurring during a period that is no longer than 4 seconds") to capture any type of unexpected changes with an IBR could result in certain types of events being missed while also capturing many events that don't need to be analyzed (e.g., correct/intended responses of an IBR). The recommendation would be to include a set of event triggers as sub-requirements under Requirement R1.

Example triggers could include:

(1) ***Unexpected*** changes in active or reactive power output within a four-second period

(2) ***Unexpected*** changes in active or reactive power output ***longer*** than a four-second period, including momentary cessation, partial or full IBR tripping, or detailed recovery of active power response post-fault

(3) Active or reactive power oscillations that are poorly damped or persist for longer than *[consider value]* seconds

This structure would give the opportunity for additional triggers to be easily added and implemented/considered to more suitably capture unexpected operations occurring from IBRs on the BPS.

If additional trigger criteria are not used, another approach would be to modify the existing "within four-second window" criteria by adding additional SCADA scan rate samples into the existing trigger. Specifically, this would ensure that correctly performing dynamic events would ***not*** be considered within scope, and rather only significant power output changes that are sustained (i.e., trip of an IBR, active power output jump up/down that remains longer than a dynamic event such as momentary cessation or delayed power recovery, etc.). This would align with the language in the SAR to identify IBRs that incorrectly perform during dynamic grid events by either tripping, reducing active power, and not returning to pre-event output levels within 1-second.

Example criteria language for Requirement R1 along these lines could be:

"Changes in active power output that are the greater of either 10% of the plant's gross nameplate

rating, or 20 MW, and the change in real power output remains at the new value for two or more consecutive SCADA scan rates [or could say remains at the new value for 2 seconds or longer]."

In addition, the drafting team should consider modifying Requirement R1 and Requirement R2 so that changes in power output are not limited to just real power, but also reactive power. In fact, Requirement 2.1.2 highlights documentation a facility's ride-through performance including reactive power responses during grid events.	
Likes 0	
Dislikes 0	
Response	
The DT considered all of your comments during the development of the standard. However, the DT determined that at least 20 MW or at least 10% would eliminate smaller events and appropriately balance risks while ensuring reliability. For the former, the RC still has the capability to identify events and require analysis. For the latter, the analysis would be rather simple for the GO. The DT considered all the suggested triggers however we settled on the current trigger in Requirement R1 which should capture the bulk of the issues confronting the grid.	
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 the comment and opinion.	

End of Report

Reminder

Standards Announcement

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

Additional Ballots and Non-binding Poll Open through August 12, 2024

Now Available

Additional ballots for draft three of **PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are 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 Board 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.

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 Standards Developer, Josh Blume (via email) or at 470-755-0346. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues observer list” in the Description Box.

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404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

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

Formal Comment Period Open through August 12, 2024

Now Available

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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 Standards Developer, Josh Blume (via email) or at 470-755-0346. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues 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

NERC Balloting Tool

- Dashboard
- Users
  - Registered Ballot Body
  - Proxy Ballot Body
  - My User Profile
- Ballots
  - Ballot Events
  - Ballot Results
- Comment Forms
  - View Comment Forms

Login / Register

Dashboard

NERC Standards Balloting System

Welcome Guest User, your Role is Guest

Please use the links below, or the top navigation menu to navigate the NERC Standards Balloting System Website.

Users

Registered Ballot Body
Proxy Ballot Body
My User Profile

Ballots

Ballots Events
Ballot Results

Comment Forms

View Real-time Comments

Ballot Results

Comment: View Comment Results
Ballot Name: 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues 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: 250
Total Ballot Pool: 278
Quorum: 89.93
Quorum Established Date: 8/12/2024 3:34:15 PM
Weighted Segment Value: 85.2

Actions

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	76	1	39	0.813	9	0.188	0	20	8
Segment: 2	8	0.6	6	0.6	0	0	0	2	0
Segment: 3	60	1	38	0.809	9	0.191	0	8	5
Segment: 4	13	0.9	9	0.9	0	0	0	3	1
Segment: 5	70	1	34	0.756	11	0.244	0	16	9
Segment: 6	44	1	25	0.735	9	0.265	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: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.5	5	0.5	0	0	0	2	0
Totals:	278	6	156	5.112	38	0.888	0	56	28

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu	Jay Sethi	None	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A

1	Black Hills Corporation	Micah Runner		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		Abstain	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
3	Manitoba Hydro	Mike Smith	Stephen Sines	None	N/A
6	AEP	Mathew Miller		Negative	Comments Submitted
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
5	American Municipal Power	Amy Ritts		Abstain	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A

3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Abstain	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
6	Manitoba Hydro	Brandin Stoesz		None	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A

5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A
6	Great River Energy	Brian Meloy		Affirmative	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted
5	NextEra Energy	Richard Vendetti		Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
5	Constellation	Alison MacKellar		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Abstain	N/A
1	Salt River Project	Laura Somak	Israel Perez	Negative	Comments Submitted
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
1	Eversource Energy	Joshua London		Abstain	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
3	Entergy	James Keele		Negative	Comments

					Submitted
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
1	Duke Energy	Katherine Street	Ellese Murphy	Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
6	Muscatine Power and Water	Nicholas Burns		None	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Muscatine Power and Water	Chance Back		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		None	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Abstain	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		None	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A

1	Western Area Power Administration	Ben Hammer		Negative	Third-Party Comments
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Comments Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
1	Austin Energy	Thomas Standifur		None	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
4	Austin Energy	Tony Hua		Abstain	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Abstain	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A

3	Colorado Springs Utilities	Hillary Dobson		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
5	Enel Green Power	Natalie Johnson		Abstain	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Abstain	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A

4	Western Power Pool	Kevin Conway		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
1	JEA	Joseph McClung		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Leo Bernier		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	JEA	John Babik		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A

Ballot Results

Ballot Name: 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues PRC-030-1 | 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: 236
Total Ballot Pool: 262
Quorum: 90.08
Quorum Established Date: 8/12/2024 3:23:51 PM
Weighted Segment Value: 70.55

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	73	1	31	0.738	11	0.262	24	7
Segment: 2	7	0.4	4	0.4	0	0	3	0
Segment: 3	56	1	29	0.725	11	0.275	13	3
Segment: 4	13	0.9	7	0.7	2	0.2	3	1
Segment: 5	66	1	24	0.649	13	0.351	20	9
Segment: 6	41	1	16	0.593	11	0.407	8	6
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: 10	6	0.4	4	0.4	0	0	2	0
Totals:	262	5.7	115	4.204	48	1.496	73	26

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke		Abstain	N/A

10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
6	AEP	Mathew Miller		Negative	Comments Submitted
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
	Edison International - Southern California Edison				

3	Company	Romel Aquino		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Abstain	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Abstain	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Negative	Comments Submitted
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A

5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A
6	Great River Energy	Brian Meloy		Affirmative	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
5	NextEra Energy	Richard Vendetti		Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
5	Constellation	Alison MacKellar		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Abstain	N/A
1	Salt River Project	Laura Somak	Israel Perez	Negative	Comments Submitted
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
1	Eversource Energy	Joshua London		Abstain	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
3	Entergy	James Keele		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A

1	Duke Energy	Katherine Street	Ellese Murphy	Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
6	Muscatine Power and Water	Nicholas Burns		None	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Muscatine Power and Water	Chance Back		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		None	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		None	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A

5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
1	Austin Energy	Thomas Standifur		None	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
4	Austin Energy	Tony Hua		Abstain	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Abstain	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-		Affirmative	N/A

		Holliday			
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Abstain	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Abstain	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
5	Enel Green Power	Natalie Johnson		Abstain	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Abstain	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Abstain	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Abstain	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
4	Western Power Pool	Kevin Conway		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
1	JEA	Joseph McClung		Affirmative	N/A

4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Leo Bernier		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted

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-030-1 is posted for a 17-day formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 25, 2023
SAR posted for comment	February 22, 2023 – March 23, 2023
25-day formal comment period with ballot	March 25, 2024 – April 18, 2024
34-day formal comment period with additional ballot	June 7, 2024 – July 10, 2024
22-day formal comment period with additional ballot	July 22, 2024 – August 12, 2024

Anticipated Actions	Date
17-day formal comment period with additional ballot	August 28 – September 13, 2024
5-day final ballot	TBD
Board adoption	October 8-9, 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:** Unexpected Inverter-Based Resource Event Mitigation

2. **Number:** PRC-030-1

3. **Purpose:** Identify, analyze, and mitigate unexpected Inverter-Based Resource (IBR) change of power output.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner

   4.2. Facilities:

   4.2.1. Bulk Electric System (BES) Inverter-Based Resources; and

   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.

5. **Effective Date:** See Implementation Plan for PRC-030-1

B. Requirements and Measures

R1. Each applicable Generator Owner shall implement a documented process 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 4 second period. Changes in Real Power for the following are excluded: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- 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 IBR generator; or
- Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.

M1. Each applicable Generator Owner shall have evidence which includes but is not limited to: (1) the documented process for detecting changes in output as described in Requirement R1, (2) evidence to demonstrate implementation of its documented process, (3) actual data recordings, and (4) identification of gross nameplate rating.

R2. Each applicable Generator Owner, within 90 calendar days of a Real Power change event pursuant to Requirement R1 or following a request from its associated Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the Inverter-Based Resource(s) Real Power output, shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in Real Power output;

2.1.2. Document the facility's Ride-through performance including Reactive Power response during the event;

2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities.

2.2. Upon request, provide the analysis results to the requesting associated Reliability Coordinator, Balancing Authority, or Transmission Operator.

M2. Each applicable Generator Owner shall have dated documentation of the required analysis developed in accordance with Requirement R2. Evidence may include, but is not limited to: (1) an analysis report, (2) actual data recordings or derivations, (3) documents describing the device specification and device configuration or settings, and (4) plant configuration.

R3. If performance issues and a need for corrective actions were identified in Requirement R2 Part 2.1.3, each applicable Generator Owner shall, within 60 calendar days of completing the analysis in Requirement R2, develop one of the following and provide it to the associated Reliability Coordinator, Balancing Authority, and Transmission Operator: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- A Corrective Action Plan (CAP) for the identified Inverter-Based Resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R2 Part 2.1.3; or
- A technical justification that addresses why corrective actions will not be implemented.

M3. Each applicable Generator Owner shall have dated evidence (electronic or hardcopy format) that demonstrates it developed a CAP or a technical justification, and evidence of transmittal to the Reliability Coordinator, Balancing Authority, and Transmission Operator in accordance with Requirement R3.

R4. Each applicable Generator Owner shall, for each of its Corrective Action Plans developed pursuant to Requirement R3: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

4.1. Implement the CAP;

4.2. Update the CAP if actions or timetables change; and

4.3. Notify each associated Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

M4. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, communication with equipment manufacturers, and communication with each associated Reliability Coordinator that documents the implementation, updating, or completion of a CAP in accordance with Requirement R3.

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 shall keep data or evidence of Requirement R1, and R2, Measure M1, and M2 for 36 calendar months following the completion of each Requirement.
   - The Generator Owner shall retain evidence of Requirement R3, Measure M3, including any supporting analysis per Requirements R2 and R3, for a minimum of 36 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.
   - The Generator Owner shall retain evidence of Requirement R4, Measure M4 for a minimum of 36 calendar months following completion of each CAP.

   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 responsible entity failed to implement a documented process to identify changes in Real Power output in accordance with Requirement R1.
R2.	The responsible entity performed an analysis in accordance with Requirement R2, but in more than 90 calendar days but less than 120 calendar days of an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 120 or more calendar days but less than 150 calendar days of an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 150 or more calendar days but less than 180 calendar days of an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 or Part 2.1.4. OR The responsible entity failed to provide the analysis results from the requesting entity in accordance with Requirement R2, Part 2.2.	The responsible entity developed an analysis in accordance with Requirement R2, but in 180 calendar days or more of an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 and Part 2.1.4. OR The responsible entity failed to document the facility's Ride-through performance in accordance with Requirement R2, Part 2.1.2 OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The responsible entity failed to determine the susceptibility of other inverter-based resource facilities in accordance with Requirement R2, Part 2.1.3.
R3.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 60 days, but provided it within 90 days.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 90 days, but provided it within 120 days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 120 days, but provided it within 150 days OR The developed CAP did not include corrective actions for other facilities owned by the Generator Owners as identified in Requirement R2 Part 2.1.3, if necessary. OR The developed CAP or technical justification was not provided to the associated Reliability Coordinator, Balancing Authority, and Transmission Operator.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented, within 150 calendar days.
R4.	The responsible entity implemented, but failed to	N/A	N/A	The responsible entity failed to implement a CAP in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	update a CAP, when actions or timetables changed, in accordance with Requirement R4.			accordance with Requirement R4.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan.

Version History

Version	Date	Action	Change Tracking
Initial Draft	**02/06/2024**	**Draft**	
Second Draft	**06/07/2024**	**Draft**	
Third Draft	**07/22/2024**	**Draft**	
Fourth Draft	**08/28/2024**	**Draft**	

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-030-1 is posted for a 17-day formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 25, 2023
SAR posted for comment	February 22, 2023 – March 23, 2023
25-day formal comment period with ballot	March 25, 2024 – April 18, 2024
34-day formal comment period with additional ballot	June 7, 2024 – July 10, 2024
22-day formal comment period with additional ballot	July 22, 2024 – August 12, 2024

Anticipated Actions	Date
17-day formal comment period with additional ballot	August 28 – September 13, 2024
5-day final ballot	TBD
Board adoption	October 8-9, 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:** Unexpected Inverter-Based Resource Event Mitigation
2. **Number:** PRC-030-1
3. **Purpose:** Identify, analyze, and mitigate unexpected Inverter-Based Resource (IBR) change of power output.
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) Inverter-Based Resources; and ~~(2)~~
     - **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.
5. **Effective Date:** See Implementation Plan for PRC-030-1

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B. Requirements and Measures

R1. Each applicable Generator Owner shall implement a documented process 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 4 second period. Changes in Real Power for the following are excluded: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- 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 IBR generator; or
- Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.

M1. Each applicable Generator Owner shall have evidence which includes but is not limited to: (1) the documented process for detecting changes in output as described in Requirement R1, (2) evidence to demonstrate implementation of its documented process, (3) actual data recordings, and (4) identification of gross nameplate rating.

R2. Each applicable Generator Owner, within 90 calendar days of ~~identifying an~~a Real Power change event pursuant to Requirement R1 or following a request from its ~~applicable~~associated Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the Inverter-Based Resource(s) Real Power output, shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in Real Power output;

2.1.2. Document the facility's Ride-through performance including Reactive Power response during the event;

2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities.

2.2. Upon request, provide the analysis results to the requesting ~~applicable~~associated Reliability Coordinator, Balancing Authority, or Transmission Operator.

M2. Each applicable Generator Owner shall have dated documentation of the required analysis developed in accordance with Requirement R2. Evidence may include, but is not limited to: (1) an analysis report, (2) actual data recordings or derivations, (3) documents describing the device specification and device configuration or settings, and (4) plant configuration.

R3. If performance issues and a need for corrective actions were identified in Requirement R2 Part 2.1.3, each applicable Generator Owner shall, within 60 calendar days of completing the analysis in Requirement R2, develop one of the following and provide it to the ~~applicable~~associated Reliability Coordinator, Balancing Authority, and Transmission Operator: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- A Corrective Action Plan (CAP) for the identified ~~inverter-based resource~~Inverter-Based Resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R2 Part 2.1.3; or
- A technical justification that addresses why corrective actions will not be implemented.

M3. Each applicable Generator Owner shall have dated evidence (electronic or hardcopy format) that demonstrates it developed a CAP or a technical justification, and evidence of transmittal to the Reliability Coordinator, Balancing Authority, and Transmission Operator in accordance with Requirement R3.

R4. Each applicable Generator Owner shall, for each of its Corrective Action Plans developed pursuant to Requirement R3: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

4.1. Implement the CAP;

4.2. Update the CAP if actions or timetables change; and

4.3. Notify each ~~applicable~~associated Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

M4. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, communication with equipment manufacturers, and communication with each ~~applicable~~associated Reliability Coordinator that documents the implementation, updating, or completion of a CAP in accordance with Requirement R3.

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 shall keep data or evidence of Requirement R1, and R2, Measure M1, and M2 for 36 calendar months following the completion of each Requirement.
- The Generator Owner shall retain evidence of Requirement R3, Measure M3, including any supporting analysis per Requirements R2 and R3, for a minimum of 36 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.
- The Generator Owner shall retain evidence of Requirement R4, Measure M4 for a minimum of 36 calendar months following completion of each CAP.

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 responsible entity failed to implement a documented process to identify changes in ~~RealPower~~Real Power output in accordance with Requirement R1.
R2.	The responsible entity performed an analysis in accordance with Requirement R2, but in more than 90 calendar days but less than 120 calendar days of ~~first identifying~~ an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 120 or more calendar days but less than 150 calendar days of ~~first identifying~~ an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 150 or more calendar days but less than 180 calendar days of ~~first identifying~~ an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 or Part 2.1.4. OR The responsible entity failed to provide the analysis results from the requesting entity in accordance with Requirement R2, Part 2.2.	The responsible entity developed an analysis in accordance with Requirement R2, but in 180 calendar days or more of ~~first identifying~~ an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 and Part 2.1.4. OR The responsible entity failed to document the facility's ~~ride-through~~Ride-through performance in accordance with Requirement R2, Part 2.1.2

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR The responsible entity failed to determine the susceptibility of other inverter-based resource facilities in accordance with Requirement R2, Part 2.1.3.
R3.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 60 days, but provided it within 90 days.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 90 days, but provided it within 120 days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 120 days, but provided it within 150 days OR The developed CAP did not include corrective actions for other facilities owned by the Generator Owners as identified in Requirement R2 Part 2.1.3, if necessary. OR The developed CAP or technical justification was not provided to the ~~applicable~~associated Reliability Coordinator, Balancing Authority, and Transmission Operator.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented, within 150 calendar days.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R4.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan.

Version History

Version	Date	Action	Change Tracking
Initial Draft	**02/06/2024**	**Draft**	
Second Draft	**06/07/2024**	**Draft**	
Third Draft	**07/22/2024**	**Draft**	
Fourth Draft	**08/28/2024**	**Draft**	

Implementation Plan

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1

Applicable Standard(s)

- PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation

Requested Retirement(s)

- None

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Generating Resources
- Ride-through
- Inverter-Based Resource (IBR)

Applicable Entities

- Generator Owner (GO)

Background

Multiple NERC disturbance reports,[1] including the Odessa disturbance report,[2] identified the undesired performance of Bulk Power System (BPS)-connected inverter-based resources (IBRs) during grid faults and have elaborated on the systemic and significant BPS reliability risks that this undesired performance can pose. IBRs may trip for many different reasons, may cease current injection due to inverter controls, or may have unwanted plant-level controller interactions. These types of issues have been extensively documented in the NERC reports. The resulting unexpected and unwarranted loss of generation poses a significant risk to BPS reliability. Project 2023-02 was initiated to address the reliability-related need and benefit by requiring analysis and mitigation of unexpected or unwarranted protection and control operations from Inverter-Based Resources (IBR) following the identification of such a performance issue.

1 https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx
2 https://www.nerc.com/pa/rrm/ea/Pages/May-June-2021-Odessa-Disturbance.aspx

In October 2023, FERC issued Order No. 901,[3] which directs the development of new or modified reliability standards, including 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[4]. Within the work plan, NERC identified three active Standards Development Projects that would need to be filed for regulatory approval with FERC November 4, 2024. These projects include 2020-02 Modifications to PRC-024 (Generation Ride Through),[5] 2021-04 Modifications to PRC-002-2,[6] and 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues.[7]

Project 2023-02

Proposed Reliability Standard PRC-030-1 is a new Reliability Standard that requires the Generator Owner to identify, analyze, and mitigate IBR performance issues. The scope of this project was adjusted to align with associated regulatory directives from FERC Order No. 901 and the scope of other projects related to "Milestone 2" of the NERC work plan. Specifically, Reliability Standard PRC-030-1 includes four (4) Requirements that require Generator Owners to: (1) define how events are to be identified, along with exceptions that should not be identified; (2) analyze identified events; (3) create a Corrective Action Plan (CAP) or technical justification when corrective actions are needed; and (4) mitigate performance risk through CAP implementation.

Proposed Reliability Standard PRC-030-1 includes the analytics and CAPs that complement Project 2020-02, which proposes new Reliability Standard PRC-029-1 addressing Ride-through and performance requirements for IBRs. The corresponding new data recording requirements are covered in Project 2021-04 and the new PRC-028-1 Reliability Standard.

General Considerations

This implementation plan recognizes the urgent need for Reliability Standards to address IBR CAPs to reduce disturbances, as demonstrated by multiple event reports of the last decade, while providing a reasonable period for entities to develop the necessary procedures and change their protection and control settings to meet the new requirements. The ERO Enterprise acknowledges that while there are IBR currently in operation, a standard is not in place that addresses CAPs for IBR.

[3] *Reliability Standards to Address Inverter-Based Resources,* Order No.901, 185 FERC ¶ 61,042 (2023); https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false

[4] *See Informational Filing of the N. Am. Elec. Reliability Corp. Regarding the Development of Reliability Standards Responsive to Order No. 901.*, Docket No. RM22-12-000 (January 18, 2024).

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

[6] *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

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

The ERO Enterprise acknowledges that Generator Owners and Generator Operators owning or operating BPS 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-030-1'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 BPS.

This implementation plan requires that all BES IBRs fully comply with the requirements by the effective date. It requires that applicable non-BES IBRS[8] comply by the later of: (1) January 1, 2027; or (2) the effective date of the standard.

Effective Date

The effective date for the proposed Reliability Standard is provided below.

Standard PRC-030-1

Where approval by an applicable governmental authority is required, Reliability Standard PRC-030-1 shall become effective on the 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, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard PRC-030-1 shall become effective on the later of 1) the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees; or 2) the first day of the first calendar quarter that is twelve (12) months after the date Reliability Standard PRC-029-1 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

PRC-030-1 Phased-in Compliance Dates

Requirements R1, R2, R3, and R4

[8] 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."

Bulk-Electric System IBRs

Bulk Electric System IBRS shall initially comply with all Requirements by the effective date of the standard.

Applicable Non-BES IBRs

Applicable Non-BES Inverter-Based Resources shall initially comply with Requirements R1, R2, R3, and R4 by the later of: (1) January 1, 2027; or (2) the effective date of the standard. Applicable Non-BES inverter-based resources include 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.

Implementation Plan

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1

Applicable Standard(s)

- PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation

Requested Retirement(s)

- None

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Generating Resources
- Ride-through
- Inverter-Based Resource (IBR)

Applicable Entities

- Generator Owner (GO)

Background

Multiple NERC disturbance reports,[1] including the Odessa disturbance report,[2] identified the undesired performance of ~~bulk power system~~Bulk Power System (BPS)-connected inverter-based resources (IBRs) during grid faults and have elaborated on the systemic and significant BPS reliability risks that this undesired performance can pose. IBRs may trip for many different reasons, may cease current injection due to inverter controls, or may have unwanted plant-level controller interactions. These types of issues have been extensively documented in the NERC reports. The resulting unexpected and unwarranted loss of generation poses a significant risk to BPS reliability. Project 2023-02 was initiated to address the reliability-related need and benefit by requiring analysis and mitigation of unexpected or unwarranted protection and control operations from ~~inverter-based resources~~Inverter-Based Resources (IBR) following the identification of such a performance issue.

[1] https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx
[2] https://www.nerc.com/pa/rrm/ea/Pages/May-June-2021-Odessa-Disturbance.aspx

~~After Project 2023-02 was initiated~~In October 2023, FERC issued Order No. 901,[3] which directs the development of new or modified reliability standards, including 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[4]. Within the work plan, NERC identified three active Standards Development Projects that would need to be filed for regulatory approval with FERC November 4, 2024. These projects include 2020-02 Modifications to PRC-024 (Generation Ride Through),[5] 2021-04 Modifications to PRC-002-2,[6] and 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues.[7]

Project 2023-02

Proposed Reliability Standard PRC-030-1 is a new Reliability Standard that requires the Generator Owner to identify, analyze, and mitigate IBR performance issues. The scope of this project was adjusted to align with associated regulatory directives from FERC Order No. 901 and the scope of other projects related to "Milestone 2" of the NERC work plan. Specifically, Reliability Standard PRC-030-1 includes four (4) Requirements that require Generator Owners to: (1) define how events are to be identified, along with exceptions that should not be identified; (2) analyze identified events; (3) create a Corrective Action Plan (CAP) or technical justification when corrective actions are needed; and (4) mitigate performance risk through CAP implementation.

Proposed Reliability Standard PRC-030-1 includes the analytics and CAPs that complement Project 2020-02, which proposes new Reliability Standard PRC-029-1 addressing Ride-through and performance requirements for IBRs. The corresponding new data recording requirements are covered in Project 2021-04 and the new PRC-028-1 Reliability Standard.

General Considerations

This implementation plan recognizes the urgent need for Reliability Standards to address IBR ~~Corrective Action Plans (CAP)~~CAPs to reduce disturbances, as demonstrated by multiple event reports of the last decade, while providing a reasonable period for entities to develop the necessary procedures and change their protection and control settings to meet the new requirements. The ERO Enterprise acknowledges that while there are ~~IBRs~~IBR currently in operation~~ and do not have~~, a standard is not in place that addresses CAPs for IBR~~ generation. Consistent with FERC Order No. 901, a limited and documented exemption process for those IBR is appropriate and included within this~~

[3] *Reliability Standards to Address Inverter-Based Resources,* Order No.901, 185 FERC ¶ 61,042 (2023); https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false

[4] *See Informational Filing of the N. Am. Elec. Reliability Corp. Regarding the Development of Reliability Standards Responsive to Order No. 901.*, Docket No. RM22-12-000 (January 18, 2024).

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

[6] *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

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

~~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 provides staggered timeframes by which entities shall first ensure the entity has the necessary PRC Reliability Standards, PRC-029-1, in place (12 months following regulatory approval). Subsequent compliance with the "operation" elements of these requirements shall become due as entities follow Ride-Through criteria on each applicable IBR in accordance with the implementation plan for proposed Reliability Standard PRC-029-1 – Frequency and Voltage Ride-Through Requirements for Inverter-Based Generating Resources.~~

The ERO Enterprise acknowledges that Generator Owners and Generator Operators owning or operating ~~Bulk-Power System~~BPS 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-030-1'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~~BPS.

This implementation plan requires that all BES IBRs fully comply with the requirements by the effective date. It requires that applicable non-BES IBRS[8] comply by the later of: (1) January 1, 2027; or (2) the effective date of the standard.

Effective Date

The effective date for the proposed Reliability Standard is provided below.

Standard PRC-030-1

Where approval by an applicable governmental authority is required, Reliability Standard PRC-030-1 shall become effective on the 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, or as otherwise provided for by the applicable governmental authority.

[8] 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."

Where approval by an applicable governmental authority is not required, Reliability Standard PRC-030-1 shall become effective on the later of 1) the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees; or 2) the first day of the first calendar quarter that is twelve (12) months after the date Reliability Standard PRC-029-1 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

PRC-030-1 Phased-in Compliance Dates

Requirements R1, R2, R3, and R4

~~Capability-Based Elements~~

Bulk-Electric System IBRs

~~Entities~~Bulk Electric System IBRS shall initially comply with ~~the portion of~~all Requirements ~~R1, R2, R3 and R4 relating to the **design** of their BES IBRs to meet the requirements~~ by the effective date of the standard.

Applicable Non-BES IBRs~~[8]~~

~~Entities shall not be required to~~Applicable Non-BES Inverter-Based Resources shall initially comply with Requirements R1, R2, R3, and R4 ~~relating to the **design** of their applicable non-BES IBRs until~~by the later of: (1) January 1, 2027; or (2) the effective date of the standard. Applicable Non-BES inverter-based resources include 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.

~~Performance-Based Elements (all applicable IBRs)~~

~~Entities shall not be required to comply with the portion of Requirements R1, R2, R3, and R4 relating to the **operation** of IBRs to meet the requirements until the entity has established the required Ride-through capabilities for those IBRs in accordance with the implementation plan for Reliability Standard PRC-029-1.~~

~~[8] 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."~~

Technical Rationale

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1 | August 2024

PRC-030-1 – Unexpected Inverter-Based Resource Event Mitigation

Rationale for Applicability Section
The functional entity responsible for identifying, analyzing, and mitigating unexpected Inverter Based Resources (IBR) performance is the Generator Owner (GO). The Generator Operator (GOP) is not included because of the accountability and coordination issues introduced by listing both GO and GOP as responsible functional entities. The GO is accountable for changes and improvements to the IBR and facilities necessary to mitigate performance problems. Further, this standard intentionally did not include requirements for the Balancing Authority (BA), Reliability Coordinator (RC), and Transmission Operator (TOP) because other standards (e.g., EOP-004) place requirements on these entities for system level events.

General rationale
Aligned with the Project 2023-02 Standards Authorization Request (SAR), the Requirements are structured to identify, analyze, and mitigate IBR performance issues. The SAR discusses how a series of NERC disturbance reports have “identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that these pose”. [1,] In particular, IBR performance during events has included tripping or momentary cessation that is unexpected, unwarranted, and poses reliability challenges.

Requirement R1 defines how events are to be identified, along with exceptions that should not be identified. Requirement R2 requires analysis of identified events, with specific elements assessed as described in subparts. Requirement R3 requires a Corrective Action Plan (CAP) or technical justification when corrective actions are needed. Finally, R4 requires mitigation of the performance risk through CAP implementation. The flow of these requirements is summarized in Figure 1.1.

[1] *Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Standard Authorization Request, at p. 1 (accepted August 23, 2023) (referencing Event Reports (nerc.com))*

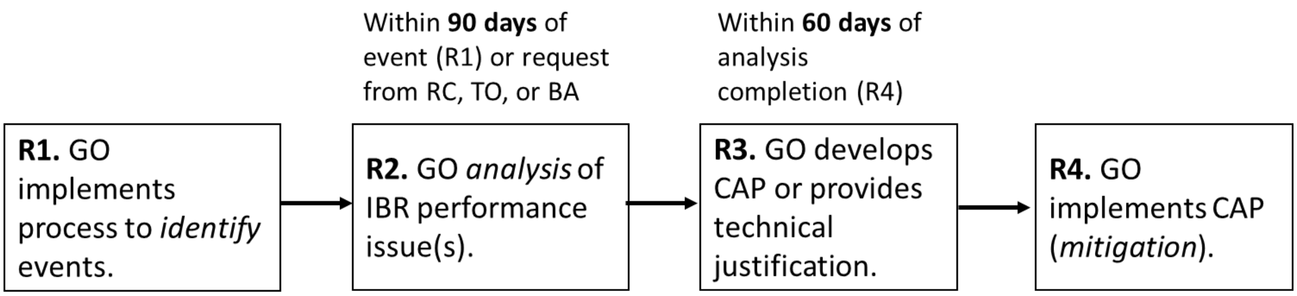


Figure 1.1: Relationship of Requirements in PRC-030-1

The Requirement R1 contains thresholds for identifying events with sudden changes in Real Power. Figure 1.2 depicts the threshold criteria and logic used in Requirement R1, along with additional details of process flow in Requirement R2.

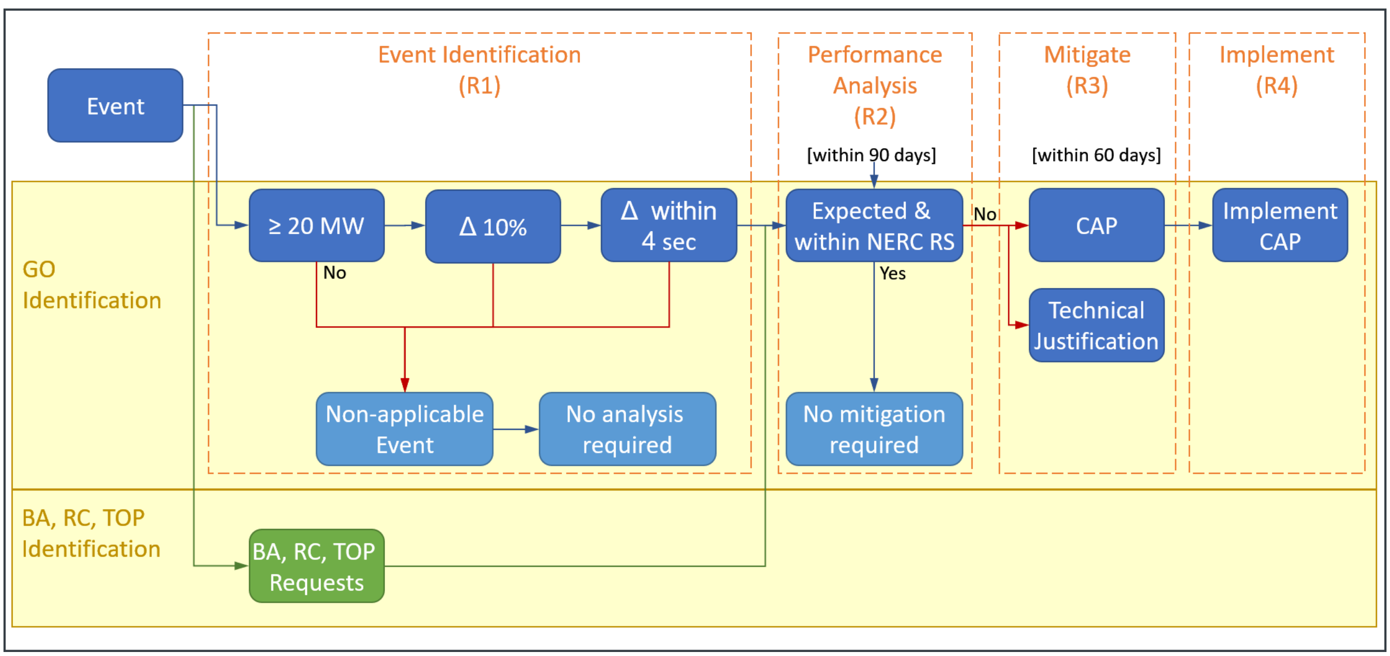


Figure 1.2: PRC-030-1 Flowchart

Rationale for Requirement R1

The intent of Requirement R1 is for the Generator Owner (GO) to implement a documented process to self-identify events that are sufficiently large to warrant an analysis of IBR performance for the identified event. For that reason, the Drafting Team included the 20 MW minimum threshold, which is a common

cutoff for other Reliability Standards, such as MOD-025, to reduce the number of potential events. NERC Category two in the ROP, entity registration section references 20 MVA as a significant threshold.

While the GO should consider both active and reactive power responses when an analysis is required, only Real Power is used as a threshold to trigger analysis. Real Power was selected as the monitored parameter to make implementation feasible across IBR plant designs and back end software system (e.g., SCADA). MW and Mvar are monitored on the SCADA software, while MVA is typically not present. The Drafting Team (DT) went with MW instead of MVA due to Real power loss being the primary concern in IBR events.

The thresholds for event identification in Requirement R1 provide a two-tier approach depending on the size of the IBR facility. The table below shows the two tiers and the thresholds that should be used to identify events. In addition, all unexpected events in which there is a complete loss of MW output, or active drops to 0 MW, should be identified regardless of plant size and output. This of course excludes planned ramp downs, and all other exclusions listed in Requirement R1 (solar end of day ramp down, planned outages, loss of connecting transmission facilities, Misoperations identified in PRC-004, etc.).

Facility Nameplate Rating	Threshold
200 MW or less	20 MW
Greater than 200 MW	10% of Nameplate Rating (e.g. 30 MW for 300 MW Facility)

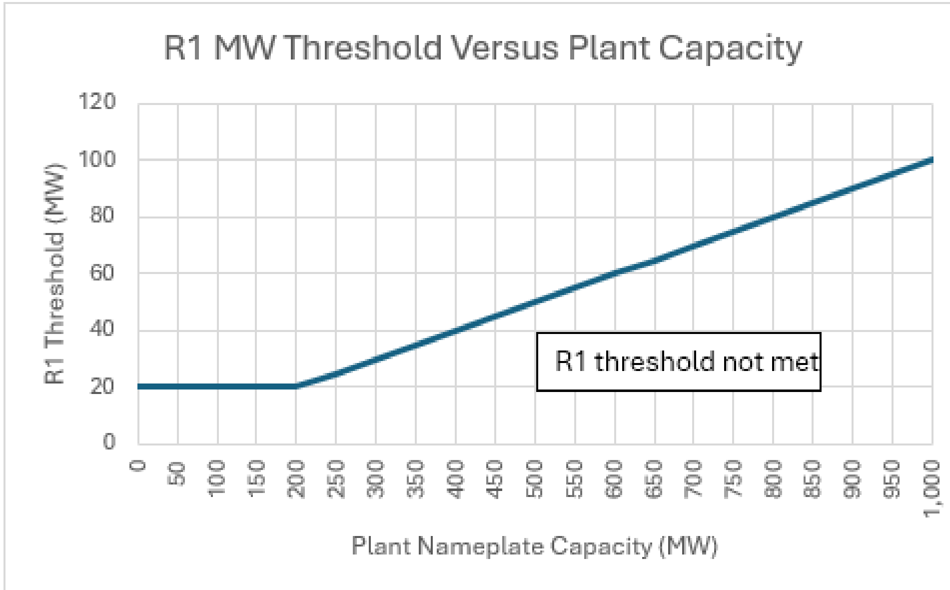
Nameplate rating was used as the basis of the change (power or amperes) because it is the common reference in NERC and other industry standards. Nameplate was chosen because every generator has a nameplate rating that can be referenced. Nameplate rating is also included as the reference point as it is included in the BES definition.

The 10% of nameplate rating for magnitude of Real Power change event threshold was chosen to be large enough to screen out small Real Power changes but low enough to detect events that should be analyzed for reliability purposes. The percent change is intended to address facilities with greater than 200 MW nameplate rating where 10% is a significant change, otherwise the 20 MW threshold sets a minimum threshold for event identification. The 20 MW minimum change threshold causes the 10% change to only apply to 200 MW facilities and above.
For smaller capacity facilities, the use of only a percent change as the screening criteria would lead to identification of disturbances that are not likely to be significant for analysis.

To restate the criteria another way:

- For plants with 0 – 200 MW gross nameplate rating, the change must be at least 20 MW,
- For plants with 200 MW gross nameplate rating and larger, the change must be at least 10% of the gross nameplate rating.

The criteria could be charted as depicted below.



Requirement R1 Threshold met

The purpose of the two limits is to make the trigger points manageable for both large and small facilities. The Drafting Team (DT) recognizes that as the plant size grows, so does the trigger threshold, which is why the threshold was set at 10% rather than something larger, like 20%. While the GO would not be required to identify events below the 10% threshold for large plants, the Reliability Coordinator (RC) is explicitly given the option to request a review in the requirement.

The DT revised the wording of Requirement R1 to clarify that the DT's intent is at least 20 MW for facilities with a nameplate rating of 200 MW or less and at least 10% change for facilities with a nameplate rating over 200 MW. While the DT considered the existing criteria sufficient, a complete loss of the facility was also included as a Requirement R1 condition.

At one point, the DT considered using the terms "sudden" and "unexpected", but that created uncertainty and concerns about consistent application. Therefore, the DT chose to bound the initial change at event onset to a four second timeframe.

The various SCADA scan rates in use at ISOs/RTOs as well as NERC standard minimum required scan rates were considered in selecting four seconds. SCADA monitoring is a likely method for monitoring Real Power changes. Power changes that occur and recover within one scan are not expected to be detected by the Requirement R1 process implemented by GOs. The four seconds was not intended to define the scan period, but only to characterize the change as sudden when considering information on monitoring capabilities across the industry. If a facility is using a scan rate of four seconds or greater to monitor Real Power output, the GO should use the change in Real Power output in one scan rate to identify events meeting Requirement R1 criteria. It should be noted that using longer time periods or scan rate could lead

to a need for more sophisticated event screening or may otherwise lead to identification of more invalid events that occur on slower timescales.

The intention of the four seconds was to limit the time within which the change in Real Power is calculated. The DT also considered that IBR generation plants following normal operation dispatch commands tend to move more slowly. For example, using the 20 MW for four seconds, the change rate is 5MW/sec, or 300 MW/min. Lower ramp rates would not be expected to meet the Requirement R1 criteria.

The following set of charts, in Figure 1.4, are examples of expected event scenarios and whether they meet the Requirement R1 criteria.

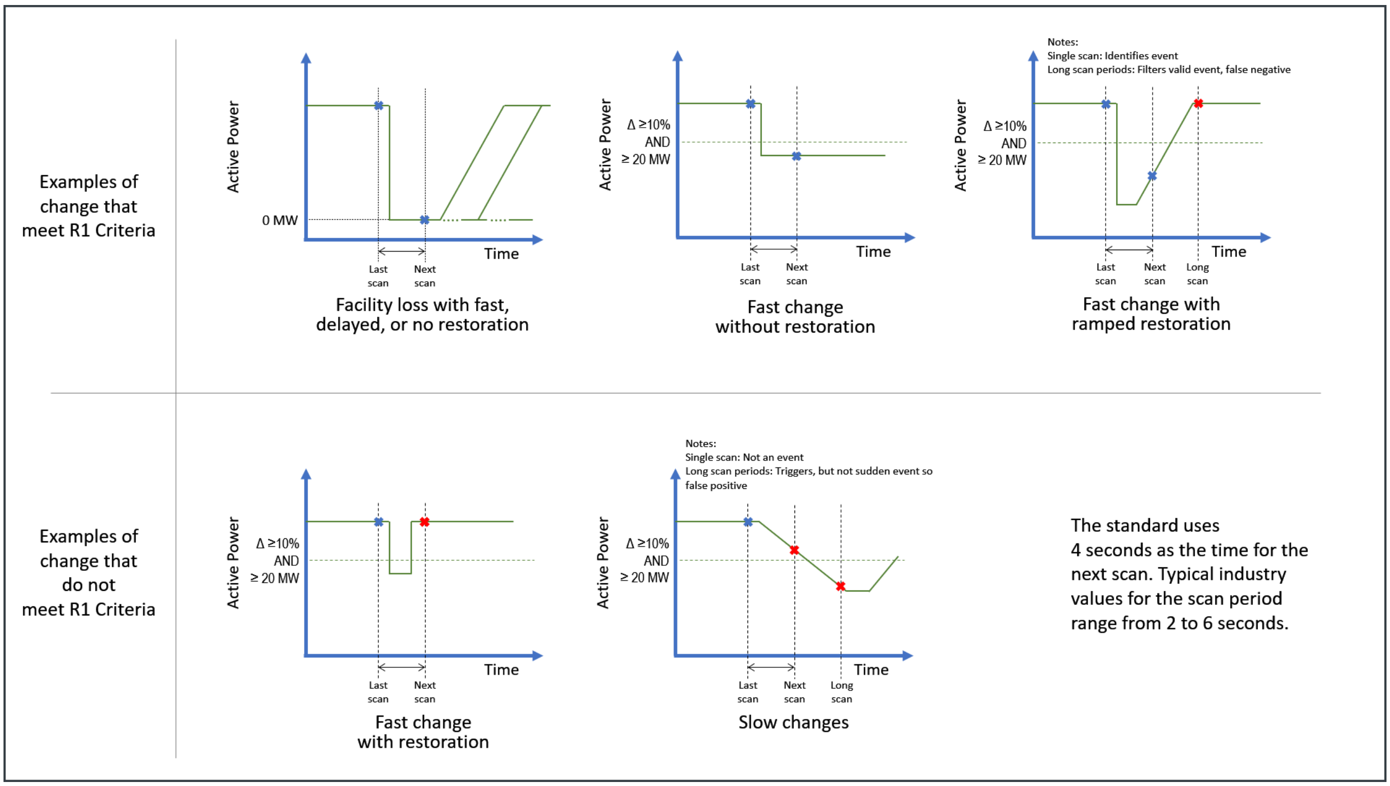


Figure 1.4: PRC-030-1 Flowchart

Due to concern voiced by industry that the thresholds defined in Requirement R1 could be often exceeded during the normal operation of an IBR facility, the DT examined three IBR facilities in Texas to determine the frequency of such events.

Solar facility in West Texas with 160 MW nameplate rating:
The DT analyzed one year of data encompassing all of 2023 and found five instances in which the facility changed 20 MW or more within a four second period. All five instances were related to ride-through performance issues previously identified by the Reliability Coordinator. There were zero events in which

Real Power changed 20 MW or more within a four second period due to change of irradiance, ramping due to dispatch, or other reasons listed as exclusions to Requirement R1.

Wind facility in Texas Panhandle with 300 MW nameplate rating:
The DT analyzed one year of data encompassing all of 2023 and found zero real events in which the facility changed 30 MW or more within a four second period. There were several events that were triggered due to dropouts of telemetry from the facility, but telemetry from the Point of Interconnection verified that there were no actual drops in Real Power from the facility at the time.

Solar Facility in Central Texas with 500 MW nameplate rating:
The DT analyzed one month of data for June 2024 and found seven events in which the facility changed 50 MW or more within a four second period, the first four of these events appear to be caused by curtailment issues. The plant was either being curtailed or was released from curtailment at the time which four of the seven events were detected. One of those events showed a large increase of irradiance at the time, but it is unclear if the change of irradiance alone caused the sudden increase in generation or if it was due to improper curtailment ramp rates, or a combination of the two. Two of the other events were related to large oscillations lasting up to an hour in which peak to peak magnitude of the oscillation exceeded 50 MW. The last event was due to a Power Plant Controller issue that caused a sudden drop in Real Power of 246 MW and was previously identified by the Reliability Coordinator. Under Requirement R1 requirements, three of the seven events would meet criteria and need to be analyzed in Requirement R2. The table below summarizes the results:

Date/Time	Four second MW change	Increase/ Decrease	Significant Irradiance Change	Cause	Should be Analyzed in R2
6/4/2024 1:25:00 PM	83	Increase	Yes	Curtailment issue/ Irradiance change?	No (Resource dispatch and/or change in irradiance exclusion)
6/4/2024 5:00:00 PM	192	Increase	No	Curtailment released	No (Resource dispatch exclusion)
6/14/2024 8:02:00 AM	57	Increase	No	Curtailment issue	No (Resource dispatch exclusion)
6/14/2024 11:36:00 AM	138	Increase	No	Curtailment issue	No (Resource dispatch exclusion)
6/17/2024 11:45:00 AM	246	Decrease	No	Plant controller issue	Yes
6/23/2024 12:30:00 PM	50	Both	No	Oscillation Event	Yes (peak to peak magnitude >50 MW observed)
6/26/2024 4:00:00 PM	78	Both	No	Oscillation Event	Yes (peak to peak magnitude >50 MW observed)

The DT also analyzed data covering one month from four facilities in Hawaii and found only one event that exceeded thresholds in Requirement R1. Since facilities in this area are generally smaller, all four facilities

analyzed were less than 200 MW in nameplate rating, so a 20 MW threshold was used for analysis. The DT also looked at an extended time period of 60 seconds, and as expected, more events were identified with the extended time period.

Plant #	1	2	3	4
Technology	Wind	PV	PV/BESS (AC Couple)	BESS Standalone
Facility Nameplate Rating (MW)	69	46	39	135
# of event (4 second, >20 MW)	0	0	0	1 (cause unknown)
# of event (60 second, >20 MW)	0	0	0	8

Due to the above analysis, the DT believes the thresholds in Requirement R1 would rarely trigger events due to normal operation of an IBR facility if the facility is operating as expected. The DT only found one possible instance of a facility exceeding the thresholds due to change of irradiance and wind speed, and it was likely caused by improper curtailment ramp rates programmed into the Power Plant Controller. In addition, the DT reviewed papers published by NREL on Solar PV Variability at Small Timescales and Variability of Wind Power Output, which concludes that change in irradiance and wind speed would not have large impacts to changes in output within a narrow timeframe such as a four second period.

The intention of the four second period was to specify what constitutes a sudden change in power, similar to the types of Real Power loss events described in NERC Disturbance Event reports. The DT considered using the term "scan period" to define the change period, because this scan period is the basis of the time, but chose to stay with the four second time specification. Four seconds is a common industry practice, MISO's scan rate, which is one of the longest, has a time duration of four seconds. The four second threshold is meant to provide a significant exclusion because the change must occur quickly, within that time. Increasing the time effectively reduces the rate of change and would identify more events than a four second window. The intent is to exclude from review slow power changes expected with normal operations (e.g., variable output from weather, dispatch, planned outages, testing) or expected responses (e.g., loss of interconnection facilities), which were defined as bullet points to Requirement R1.

The standard four second time only applies to the period of calculating the Real Power change, such as a sudden drop, to be considered valid events identified under Requirement R1. This time does not limit or imply any duration for the entire event. While the change must occur within the four second timeframe, the plant response may take tens of seconds or even minutes. The standard does specify or limit that time period.

The term "changes in Real Power" encompasses both sudden decreases (i.e., loss of output) and increases (i.e., additional consumption) that may be caused by IBR mis-operations that could affect system

reliability. For instance, a battery energy storage system that mis-measures system frequency may unexpectedly enter a charging mode and suddenly increase Real Power draw.

Photovoltaic (PV) example 1 – qualifying:
PV facility with gross nameplate rating of 220 MW is operating with active output of 80 MW. During a transmission system fault event,[2] the plant exhibits a near instantaneous Real Power output drop to 50 MW.

The change in apparent power in under four seconds is 30 MW, which exceeds 22 MW, the greater of 10% of the plant's gross nameplate (22 MW) or 20 MW. This IBR performance event is required to be captured by the GO's process implemented in Requirement R1.

PV example 2 – non-qualifying:
PV facility with gross nameplate rating of 80 MW is operating with active output of 60 MW. During a transmission line fault event,[1] the plant exhibits a near instantaneous Real Power output drop to 42 MW.

The change in apparent power in under four seconds is 18 MW, <u>not</u> exceeding 20 MW, the greater of 10% of the plant's gross nameplate rating (8 MW) or 20 MW. This IBR performance event is <u>not</u> required to be captured by the GO's Requirement R1 process.

Battery Energy Storage System (BESS) example 1 – qualifying:
BESS facility with gross nameplate power output rating of 80 MW is operating as a load drawing 50 MW. During a power plant controller (PPC) malfunction event of the BESS facility, the PPC incorrectly estimates system frequency sending an incorrect frequency response signal causing the plant to exhibit a near instantaneous change in real power to 10 MW injection.

The change in apparent power in under four seconds is 60 MW, which exceeds 20 MW, the greater of 10% of the BESS gross nameplate (8 MW) or 20 MW.
This IBR performance event is required to be captured by the GO's Requirement R1 process.

BESS example 2 – non-qualifying:
BESS facility with gross nameplate power output rating of 80 MW is outputting 40 MW. The BESS facility is curtailed by the Reliability Coordinator such that the plant exhibits a near instantaneous Real Power decrease to 15 MW.

The change in apparent power in under four seconds is 25 MW, exceeding 20 MW, the greater of 10% of the plant's gross nameplate rating (8 MW) or 20 MW. However, the change in apparent power is the result of the Reliability Coordinator curtailment which is an exempt event per Requirement R1. This IBR performance event is <u>not</u> required to be captured by the GO's Requirement R1 process.

[2] The transmission line fault is assumed not to be on the line connecting the IBR to the system, but rather is a fault remote from the IBR.

Rationale for Requirement R2

Requirement R2 requires analysis of events that meet Requirement R1 thresholds. Requirement R2 also provides an alternative path of event identification by the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operators (TOP). It is anticipated that some events would only be detected by one entity, but the combination of both identification methods would better identify events potentially posing reliability challenges.

Requirement R2 allows 90 days to analyze expected versus actual IBR responses to place an emphasis on diligent resolution, while still allowing enough time to conduct an analysis and identify causes. Ninety days allows adequate time for GO to interact with manufacturers and examine capabilities of equipment. In establishing this timeframe, the DT considered the PRC-004 timeline of 120 days, recognizing important differences between the application of these standards. PRC-004-4(i) Technical Rationale states “The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed”.[3] The PRC-004 timeframe accounts for extreme weather events such as hurricanes that may affect a very large number of Protection Systems for a given responsible entity. The volume of IBR exposed to potential expected operation is anticipated to be lower when compared to Protection Systems and therefore a shorter timeframe is appropriate for PRC-030. The 90-day period starts from the event date for GO-identified performance issues resulting from Requirement R1 or upon request from the Balancing Authority, Reliability Coordinator, or Transmission Operator regarding IBR responses identified during system events.

Requirement R2, Part 2.1 includes subparts to analyze performance during a Real power change event. Requirement R2, Part 2.1.1 requires identification of the root cause. Requirement R2, Part 2.1.2 requires that the facility’s Ride-through performance including reactive power response is documented (Requirement R2, Part2.1.2). Requirement R2, Part 2.1.3 requires that the GO assess the performance issue(s) and determine whether corrective actions are needed. Requirement R2, Part 2.1.4 requires that the GO consider the applicability of the root cause to its other IBR facilities. Collectively, the subparts define the minimum features required as part of an effective analysis. Requirement R2, Part 2.2 closes the communication loop with Balancing Authority, Reliability Coordinator, and Transmission Operator entities, should these entities request analysis results.

Rationale for Requirement R3

Should Requirement R2 determine a need for corrective actions, Requirement R3 requires a CAP or technical justification be developed within 60 calendar days of completing the analysis in Requirement R2, as identified in Requirement R2, Part 2.1.3. If Requirement R2 did not identify the need for corrective actions, then no action is required under Requirement R3.

Resolving the causes of IBR performance issues benefits BPS reliability by preventing recurrence. The CAP is an established tool for resolving operational problems. The NERC *Glossary* defines a Corrective Action Plan as, “A list of actions and an associated timetable for implementation to remedy a specific problem.”

[3] Standard PRC-004-4(i) – Protection System Misoperation Identification and Correction. Available at: https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-004-4(i).pdf

Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the IBR Performance issue cause(s) is identified in Requirement R2 or Requirement R3 requires Generator Owner(s) to develop a CAP or provide a technical justification that addresses why corrective actions will not be applied nor implemented. The CAP is provided to the Reliability Coordinator, Balancing Authority, and Transmission Operator so that these entities 1) gain information potentially relevant to recent system events, and 2) can account for potential IBR performance issues in operational risk assessments.

This standard recognizes there may be multiple causes for IBR performance issues. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a CAP to correct multiple causes of an IBR performance issue. The 60-calendar day period for developing a CAP or technical justification is established based on industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent IBR performance issues from reoccurring, the timetable for executing such actions, and an evaluation of the CAP's applicability to the GO's other IBR including those at other locations. The evaluation of these other IBR with similar designs aims to reduce the risk and the likelihood of similar IBR performance issues in other IBRs. The GO is responsible for determining the extent of its evaluation concerning other IBRs and locations. The evaluation may result in the GO including actions to address IBR at other locations or to provide a technical justification that addresses why corrective actions will not be applied nor implemented.

Acceptable technical justification for not performing corrective actions is expected to primarily have two characteristics:
1) interconnection requirements on IBR performance extending beyond those in place at the time of interconnection; and
2) it would require significant material modifications/qualified change.

Technical justifications for not performing corrective actions do not relieve the GO from compliance with other standards (i.e., PRC-029-1 Ride-Through) to the extent that other standards are applicable.

Rationale for Requirement R4

Requirement R4 requires that each applicable GO implement the CAP developed in Requirement R3, as applicable, to mitigate deficiencies identified in Requirement R2. In the NERC *Glossary*, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem."

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. If the CAP is changed, the entity must notify the applicable Reliability Coordinator(s), Transmission Operator(s), or Balancing Authority (s). The entity must also notify applicable RC(s) when the

CAP has been completed. The implementation of a properly developed CAP ensures that causes of unexpected changes in IBR power output are mitigated in a timely manner.

An IBR deficiency may require the Reliability Coordinator to impose operating restrictions so the system can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions should incentivize the entity to complete the CAP as quickly as possible.

Technical Rationale

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1 | August 2024

PRC-030-1 – Unexpected Inverter-Based Resource Event Mitigation

Rationale for Applicability Section

The functional entity responsible for identifying, analyzing, and mitigating unexpected Inverter Based Resources (IBR) performance is the Generator Owner (GO). The Generator Operator (GOP) is not included because of the accountability and coordination issues introduced by listing both GO and GOP as responsible functional entities. The GO is accountable for changes and improvements to the IBR and facilities necessary to mitigate performance problems. Further, this standard intentionally did not include requirements for the Balancing Authority (BA), Reliability Coordinator (RC), and Transmission Operator (TOP) because other standards (e.g., EOP-004) place requirements on these entities for system level events.

General rationale

Aligned with the Project 2023-02 Standards Authorization Request (SAR), the Requirements are structured to identify, analyze, and mitigate IBR performance issues. The SAR discusses how a series of NERC disturbance reports have "identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that these pose”. [1]~~[2,3,4,5,6,7,8,9]~~ In particular, IBR performance during events has included tripping or momentary cessation that is unexpected, unwarranted, and poses reliability challenges.

Requirement R1 defines how events are to be identified, along with exceptions that should not be identified. Requirement R2 requires analysis of identified events, with specific elements assessed as described in subparts. Requirement R3 requires a Corrective Action Plan (CAP) or technical justification when corrective actions are needed. Finally, R4 requires mitigation of the performance risk through CAP implementation. The flow of these requirements is summarized in Figure ~~1~~1.1.

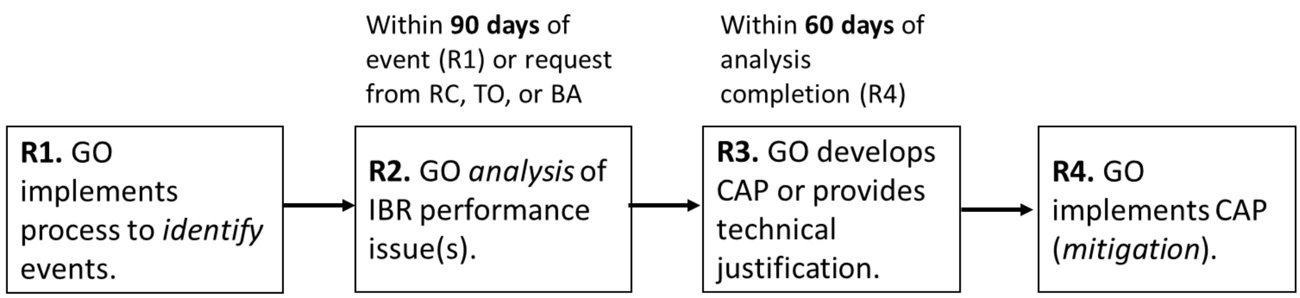


Figure 1.1: Relationship of Requirements in PRC-030-1

[1] ~~*Odessa Disturbance*, NERC. September 2021.https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf~~*Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Standard Authorization Request, at p. 1 (accepted August 23, 2023) (referencing Event Reports (nerc.com))*

~~[2] *2022 Odessa Disturbance*, NERC. Atlanta, GA: December 2022. https://www.nerc.com/comm/RSTC_Reliability_Guidelines/NERC_2022_Odessa_Disturbance_Report%20%281%29.pdf~~

~~[3] *900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*, NERC. Atlanta, GA: February 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~~

~~[4] *April and May 2018 Fault Induced Solar Photovoltaic Resource Interruption Disturbances Report*, NERC. Atlanta, GA: January 2019. https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf~~

~~[5] *Panhandle Wind Disturbance*, NERC. Atlanta, GA: August 2022. https://www.nerc.com/pa/rrm/ea/Documents/Panhandle_Wind_Disturbance_Report.pdf~~

~~[6] *Panhandle Wind Disturbance*, NERC. Atlanta, GA: August 2022. https://www.nerc.com/pa/rrm/ea/Documents/Panhandle_Wind_Disturbance_Report.pdf~~

~~[7] *1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*, NERC. 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~~

~~[8] *San Fernando Disturbance*, NERC. November 2020. https://www.nerc.com/pa/rrm/ea/Documents/San_Fernando_Disturbance_Report.pdf~~

~~[9] https://www.iec.ch/conformity-assessment/what-conformity-assessment~~

The Requirement R1 contains thresholds for identifying events with sudden changes in ~~active power~~Real Power. Figure 1.2 depicts the threshold criteria and logic used in Requirement R1, along with additional details of process flow in Requirement R2.

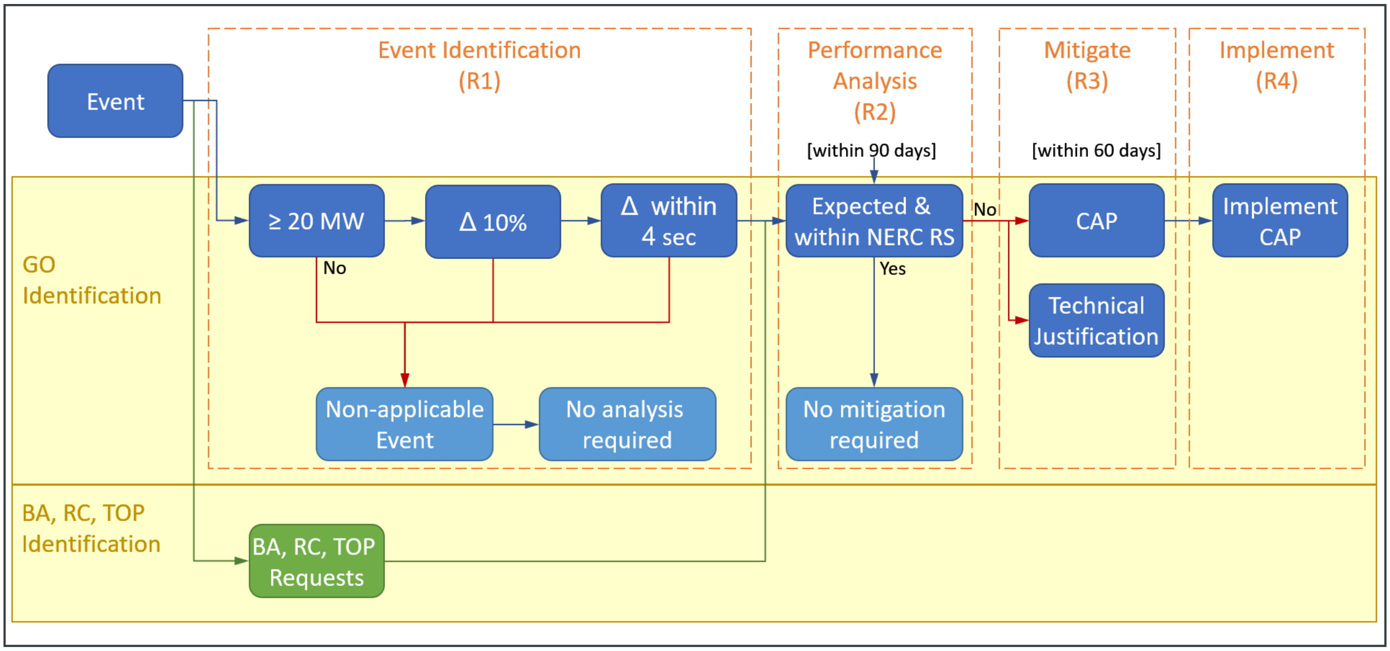


Figure 1.2: PRC-030-1 Flowchart

Rationale for Requirement R1

The intent of Requirement R1 is for the Generator Owner (GO) to implement a documented process to self-identify events that are sufficiently large to warrant an analysis of IBR performance for the identified event. For that reason, the ~~team~~Drafting Team included the 20 MW minimum threshold, which is a common cutoff for other Reliability Standards, such as MOD-025, to reduce the number of potential events. NERC Category two in the ROP, entity registration section references 20 MVA as a significant threshold.

While the GO should consider both active and reactive power responses when an analysis is required, only ~~active power~~Real Power is used as a threshold to trigger analysis. ~~Active power~~Real Power was selected as the monitored parameter to make ~~feasible~~ implementation feasible across IBR plant designs and ~~backend~~back end software system (e.g., SCADA). MW and Mvar are monitored on the SCADA software, while MVA is typically not present. The Drafting Team (DT) went with MW instead of MVA due to Real power loss being the primary concern in IBR events.

The thresholds for event identification in Requirement R1 ~~effectively~~ provide a two-tier approach depending on the size of the IBR facility. The table below shows the two tiers and the thresholds that should be used to identify events. In addition, all unexpected events in which there is a complete loss of MW output, or active drops to 0 MW, should be identified regardless of plant size and output. This of course excludes planned ramp downs, and all other exclusions listed in Requirement R1 (solar end of day ramp down, planned outages, loss of connecting transmission facilities, Misoperations identified in PRC-004, etc.).

Facility Nameplate Rating	Threshold
200 MW or less	20 MW
Greater than 200 MW	10% of Nameplate Rating (e.g. 30 MW for 300 MW Facility)

Nameplate rating was used as the basis of the change (power or amperes) because it is the common reference in NERC and other industry standards. ~~The IBR continuous rating concept outlined in IEEE 2800-2022 definitions was considered and determined to be a departure from NERC standards approaches to date.~~Nameplate was chosen because every generator has a nameplate rating that can be referenced. Nameplate rating is also included as the reference point as it is included in the BES definition.

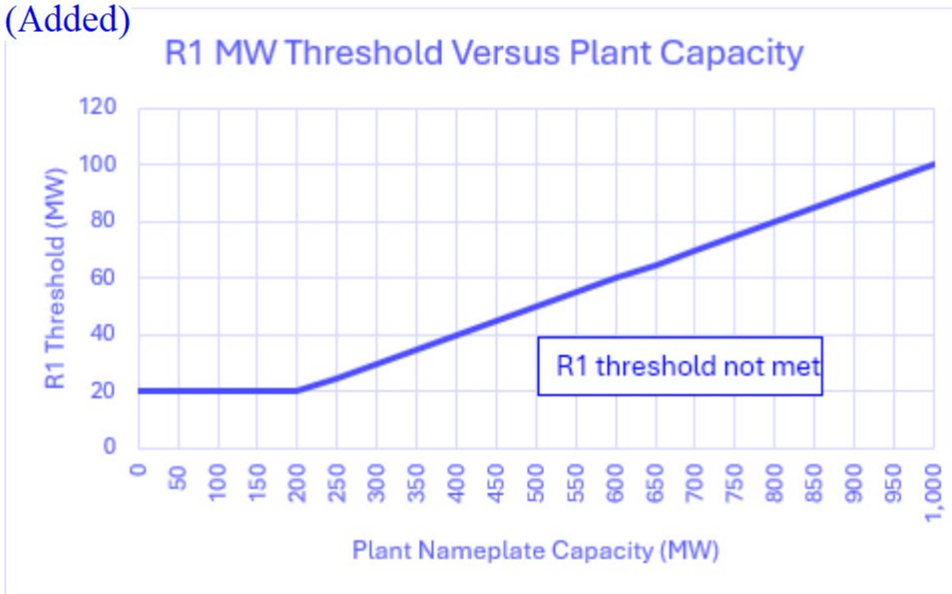
The 10% of nameplate rating for magnitude of Real Power change event threshold was chosen to be large enough to screen out small ~~active power~~Real Power changes but low enough to detect events that should be analyzed for reliability purposes. The percent change is intended to address facilities with greater than 200 MW nameplate rating where 10% is a significant change, otherwise the 20 MW threshold sets a minimum threshold for event identification. The 20 MW minimum change threshold causes the 10% change to only apply to 200 MW facilities and above.
For smaller capacity facilities, the use of only a percent change as the screening criteria would lead to identification of disturbances that are not likely to be significant for analysis.

To restate the criteria another way:

- For plants with 0 – 200 MW gross nameplate rating, the change must be at least 20 MW,
- For plants with 200 MW gross nameplate rating and larger, the change must be at least 10% of the gross nameplate rating.

The criteria could be charted as depicted below.

(Added)



Requirement R1 Threshold met

The purpose of the two limits is to make the trigger points manageable for both large and small facilities. The Drafting Team (DT) recognizes that as the plant size grows, so does the trigger threshold, ~~that~~which is why the threshold was set at 10% rather than something larger, like 20%. While the GO would not be required to identify events below the 10% threshold for large plants, the Reliability Coordinator (RC) is explicitly given the option to request a review in the requirement.

The DT revised the wording of Requirement R1 to clarify that the ~~DT~~DT's intent is at least 20 MW ~~and~~for facilities with a nameplate rating of 200 MW or less and at least 10% change~~, not 20~~ for facilities with a nameplate rating over 200 MW~~ or 10%~~. While the DT considered the existing criteria sufficient, a complete loss of the facility was also included as ~~an~~a Requirement R1 condition.

At one point, the DT considered using the terms "sudden" and "unexpected", but that ~~led to much~~created uncertainty and ~~discussion as to how that would be applied consistently~~concerns about consistent application. Therefore, the DT chose to bound the initial change at event onset to a ~~4~~four second timeframe.

The various SCADA scan rates in use at ISOs/RTOs as well as NERC standard minimum required scan rates were considered in selecting four seconds. SCADA monitoring is a likely method for monitoring ~~active power~~Real Power changes. Power changes that occur and recover within one scan are not expected to be detected by the Requirement R1 process implemented by GOs. The four seconds was not intended to define the scan period, but only to characterize the change as sudden when considering information on monitoring capabilities across the industry. If a facility is using a scan rate of ~~4~~four seconds or greater to monitor ~~active power~~Real Power output, the GO should use the change in ~~active power~~Real Power output in one scan rate to identify events meeting Requirement R1 criteria. It should be noted that using longer time periods or scan rate could lead to a need for more sophisticated event screening or may otherwise lead to identification of more invalid events that occur on slower timescales.

The intention of the four seconds was to limit the time within which the change in Real Power is calculated. The DT also considered that ~~units~~IBR generation plants following normal operation dispatch commands tend to move more slowly. ~~Using~~For example, using the 20 MW for ~~4 sec~~four seconds, the change rate is 5MW/sec, or 300 MW/min. Lower ramp rates would not be expected to meet the Requirement R1 criteria.

The following set of charts, in Figure 1.4, are examples of expected event scenarios and whether they meet the Requirement R1 criteria.

(Added)

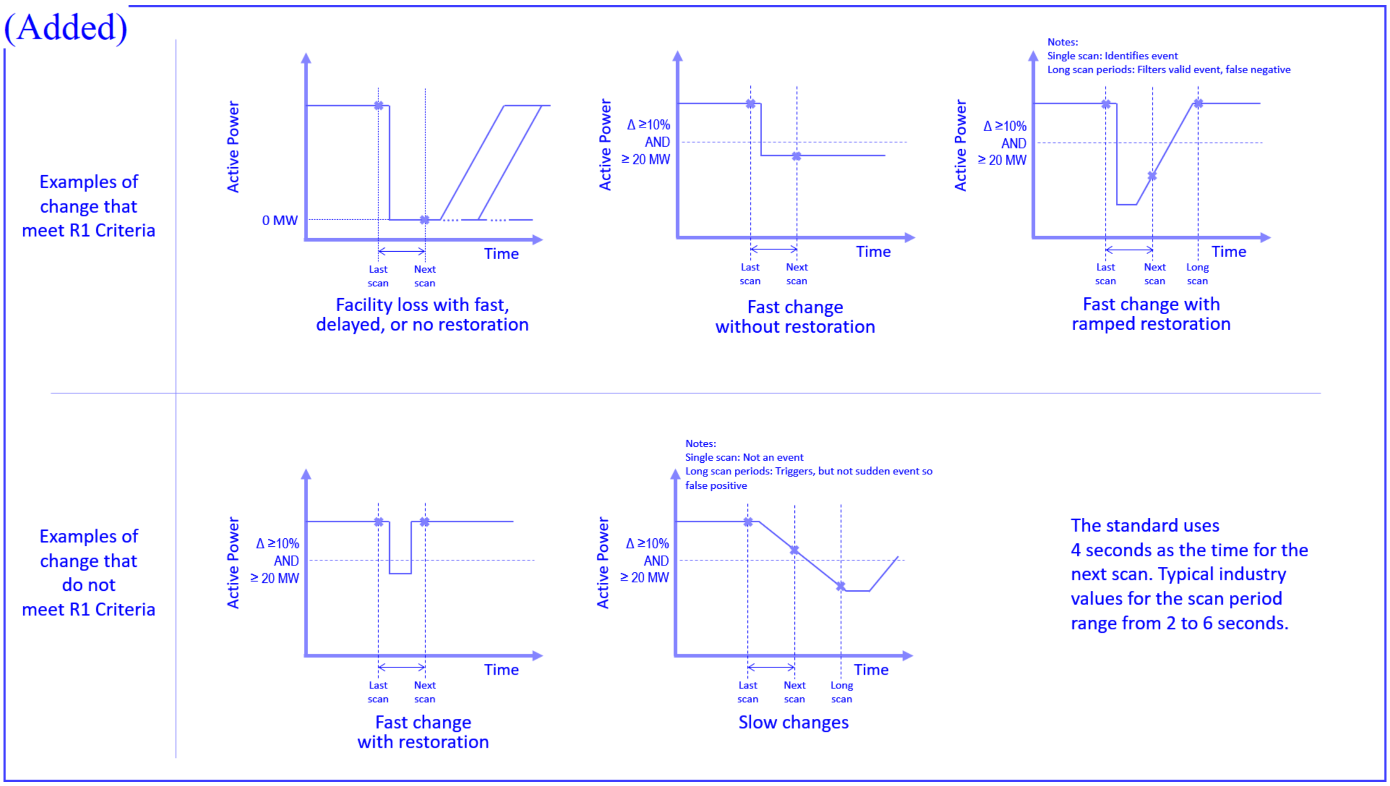


Figure 1.4: PRC-030-1 Flowchart

Due to concern voiced by industry that the thresholds defined in Requirement R1 could be often exceeded during the normal operation of an IBR facility, the DT examined three IBR facilities in Texas to determine the frequency of such events.

Solar facility in West Texas with 160 MW nameplate rating:
The DT analyzed one year of data encompassing all of 2023 and found ~~5~~five instances in which the facility changed 20 MW or more within a ~~4~~four second period. All ~~5~~five instances were related to ride-through performance issues previously identified by the ~~RC~~Reliability Coordinator. There were zero events in which ~~active power~~Real Power changed 20 MW or more within ~~4~~a four second period due to change of irradiance, ramping due to dispatch, or other reasons listed as exclusions ~~in the~~to Requirement R1~~ bullet list~~.

Wind facility in Texas Panhandle with 300 MW nameplate rating:
The DT analyzed one year of data encompassing all of 2023 and found zero real events in which the facility changed 30 MW or more within a ~~4~~four second period. There were several events that were triggered due to ~~drop outs~~dropouts of telemetry from the facility, but telemetry from the ~~POI~~Point of Interconnection verified that there were no actual drops in ~~active power~~Real Power from the facility at the time.

Solar Facility in Central Texas with 500 MW nameplate rating:
The DT analyzed one month of data for June 2024 and found ~~7~~seven events in which the facility changed 50 MW or more within a ~~4~~four second period~~. This facility appears to have~~, the first four of these events appear to be caused by curtailment issues~~ and is not following proper ramp rates during curtailment~~. The plant was either being curtailed or was released from curtailment at the time which ~~4~~four of the ~~7~~seven events were detected. One of those events showed a large increase of irradiance at the time, but it is unclear if the change of irradiance alone caused the sudden increase in generation or if it was due to improper curtailment ramp rates, or a combination of the two. Two of the other events were related to large oscillations lasting up to an hour in which peak to peak magnitude of the oscillation exceeded 50 MW. The last event was due to a Power Plant Controller issue that caused a sudden drop in ~~active power~~Real Power of 246 MW and was previously identified by the ~~RC~~Reliability Coordinator. Under Requirement R1 requirements, ~~3~~three of the ~~7~~seven events would meet criteria and need to be analyzed in Requirement R2. The table below summarizes the results:

Date/Time	~~4~~Four second MW change	Increase/ Decrease	Significant Irradiance Change	Cause	Should be Analyzed in R2
6/4/2024 1:25:00 PM	83	Increase	Yes	Curtailment issue/ Irradiance change?	No (Resource dispatch and/or change in irradiance exclusion)
6/4/2024 5:00:00 PM	192	Increase	No	Curtailment released	No (Resource dispatch exclusion)
6/14/2024 8:02:00 AM	57	Increase	No	Curtailment issue	No (Resource dispatch exclusion)
6/14/2024 11:36:00 AM	138	Increase	No	Curtailment issue	No (Resource dispatch exclusion)
6/17/2024 11:45:00 AM	246	Decrease	No	Plant controller issue	Yes
6/23/2024 12:30:00 PM	50	Both	No	Oscillation Event	Yes (peak to peak magnitude >50 MW observed)
6/26/2024 4:00:00 PM	78	Both	No	Oscillation Event	Yes (peak to peak magnitude >50 MW observed)

The DT also analyzed data covering one month from four facilities in Hawaii~~,~~ and found only one event that exceeded thresholds in Requirement R1. Since facilities in this area are generally smaller, all four facilities analyzed were less than 200 MW in nameplate rating, so a 20 MW threshold was used for analysis. The DT also looked at an extended time period of 60 seconds, and as expected, more events were identified with the extended time period.

Plant #	1	2	3	4
Technology	Wind	PV	PV/BESS (AC Couple)	BESS Standalone
Facility Nameplate Rating (MW)	69	46	39	135
# of event (4 second, >20 MW)	0	0	0	1 (cause unknown)
# of event (60 second, >20 MW)	0	0	0	8

Due to the above analysis, the DT believes the thresholds in Requirement R1 would rarely trigger events due to normal operation of an IBR facility if the facility is operating as expected. The DT only found one possible instance of a facility exceeding the thresholds due to change of irradiance and wind speed, and it ~~is~~was likely ~~one of those events was~~ caused by improper curtailment ramp rates programmed into the ~~PPC~~Power Plant Controller. In addition, the DT reviewed papers published by NREL on Solar PV Variability at Small Timescales and Variability of Wind Power Output, which concludes that change in irradiance and wind speed would not have large impacts to changes in output within a narrow timeframe such as a ~~4~~four second period.

The intention of the four second period was to ~~define~~specify what constitutes a sudden change in power, similar to the types of ~~active power~~Real Power loss events described in NERC Disturbance Event reports. The DT considered using the term "scan period" to define the change period, because this scan period is the basis of the time, but chose to stay with the ~~4~~four second time specification. ~~The 4~~Four seconds is a common industry practice, MISO's scan rate, which is one of the longest, has a time duration of four seconds. The four second threshold is meant to provide a significant exclusion because the change must occur quickly, within that time. Increasing the time effectively reduces the rate of change and would identify more events than a ~~4~~four second window. The intent is to exclude from review slow power changes expected with normal operations (e.g., variable output from weather, dispatch, planned outages, testing) or expected responses (e.g., loss of interconnection facilities), which were defined as bullet points to Requirement R1.

The standard ~~4~~four second time only applies to the period of calculating the ~~power~~Real Power change, such as a sudden drop, to be considered valid events identified under Requirement R1. This time ~~qualifies what is a sudden or fast change but~~ does not limit or imply any duration for the entire event. While the change must occur within the ~~4~~four second timeframe, the plant response may take ~~10's~~tens of seconds or even minutes. The standard does ~~to~~ specify or limit that time period.

~~If the facility output changes and then returns to pre-event levels within 4 seconds (dip and return), then the DT recognizes that would not be an event identified by the criteria. Similarly, because of the~~

~~randomness of events and data sampling, it is possible that a change less than 4 seconds can be identified, but those events technically do not meet the criteria.~~
The term "changes in ~~active power~~Real Power" encompasses both sudden decreases (i.e., loss of output) and increases (i.e., additional consumption) that may be caused by IBR mis-operations that could affect system reliability. For instance, a battery energy storage system that mis-measures system frequency may unexpectedly enter a charging mode and suddenly increase ~~active power~~Real Power draw.

Photovoltaic (PV) example 1 – qualifying:
PV facility with gross nameplate rating of 220 MW is operating with active output of 80 MW. During a transmission system fault event,[~~10~~2] the plant exhibits a near instantaneous ~~active power~~Real Power output drop to 50 MW.

The change in apparent power in under four seconds is 30 MW, which exceeds 22 MW, the greater of 10% of the plant's gross nameplate (22 MW) or 20 MW. This IBR performance event is required to be captured by the GO's process implemented in Requirement R1.

PV example 2 – non-qualifying:
PV facility with gross nameplate rating of 80 MW is operating with active output of 60 MW. During a transmission line fault event,[1] the plant exhibits a near instantaneous ~~active power~~Real Power output drop to 42 MW.

The change in apparent power in under four seconds is 18 MW, not exceeding 20 MW, the greater of 10% of the plant's gross nameplate rating (8 MW) or 20 MW. This IBR performance event is not required to be captured by the GO's Requirement R1 process.

Battery Energy Storage System (BESS) example 1 – qualifying:
BESS facility with gross nameplate power output rating of 80 MW is operating as a load drawing 50 MW. During a power plant controller ("PPC") malfunction event of the BESS facility, the PPC incorrectly estimates system frequency sending an incorrect frequency response signal causing the plant to exhibit a near instantaneous change in real power to 10 MW injection.

The change in apparent power in under four seconds is 60 MW, which exceeds 20 MW, the greater of 10% of the BESS gross nameplate (8 MW) or 20 MW.
This IBR performance event is required to be captured by the GO's Requirement R1 process.

BESS example 2 – non-qualifying:
BESS facility with gross nameplate power output rating of 80 MW is outputting 40 MW. The BESS facility is curtailed by the ~~RC~~Reliability Coordinator such that the plant exhibits a near instantaneous ~~active power~~Real Power decrease to 15 MW.

[~~10~~2] The transmission line fault is assumed not to be on the line connecting the IBR to the system, but rather is a fault remote from the IBR.

The change in apparent power in under four seconds is 25 MW, exceeding 20 MW, the greater of 10% of the plant’s gross nameplate rating (8 MW) or 20 MW. However, the change in apparent power is the result of the ~~RC~~Reliability Coordinator curtailment which is an exempt event per Requirement R1. This IBR performance event is not required to be captured by the GO’s Requirement R1 process.

Rationale for Requirement R2

Requirement R2 requires analysis of events that meet Requirement R1 thresholds. Requirement R2 also provides an alternative path of event identification by the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operators (TOP). It is anticipated that some events would only be detected by one entity, but the combination of both identification methods would better identify events potentially posing reliability challenges.

Requirement R2 allows 90 days to analyze expected versus actual IBR responses to place an emphasis on diligent resolution, while still allowing enough time to conduct an analysis and identify causes. Ninety days allows adequate time for ~~Generator Owners (~~GO~~)~~ to interact with manufacturers and examine capabilities of equipment. ~~This time was chosen to be closer to~~In establishing this timeframe, the DT considered the PRC-004 timeline of 120 days~~ while~~, recognizing important differences between the application of these standards. PRC-004-4(i) Technical Rationale states “The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed”.[~~11~~3] The PRC-004 timeframe accounts for extreme weather events such as hurricanes that may affect a very large number of Protection Systems for a given responsible entity. The volume of IBR exposed to potential expected operation is anticipated to be lower when compared to Protection Systems and therefore a shorter timeframe is appropriate for PRC-030. The 90-day period starts from the event date for GO-identified performance issues resulting from Requirement R1 or upon request from the Balancing Authority~~ (BA)~~, Reliability Coordinator~~ (RC)~~, or Transmission Operator ~~(TOP) ~~regarding IBR responses identified during system events.

Requirement ~~R2.1 has~~R2, Part 2.1 includes subparts to ~~ensure the root cause is identified (R2.1.1); the facility Ride through and~~analyze performance during a Real power change event. Requirement R2, Part 2.1.1 requires identification of the root cause. Requirement R2, Part 2.1.2 requires that the facility’s Ride-through performance including reactive power ~~performance~~response is documented (~~R2.1.2); the issue is assessed and determination~~Requirement R2, Part2.1.2). Requirement R2, Part 2.1.3 requires that the GO assess the performance issue(s) and determine whether corrective actions are needed~~ (R2.1.3); and~~. Requirement R2, Part 2.1.4 requires that the GO consider the applicability ~~to other similarly designed units is considered (R2.1.4)~~of the root cause to its other IBR facilities. Collectively, the subparts define the minimum features required as part of an effective analysis. Requirement ~~R2.2~~R2, Part 2.2 closes the communication loop with ~~BA, RC, and TOP~~Balancing Authority, Reliability Coordinator, and Transmission Operator entities, should these entities request analysis results.

[~~11~~3] Standard PRC-004-4(i) – Protection System Misoperation Identification and Correction. Available at: https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-004-4(i).pdf

Rationale for Requirement R3

Should Requirement R2 determine a need for corrective actions, Requirement R3 requires a CAP or technical justification be developed within 60 calendar days of completing the analysis in Requirement R2, as identified in Requirement R2, Part 2.1.3. If Requirement R2 did not identify the need for corrective actions, then no action is required under Requirement R3 ~~does not need to be performed~~.

Resolving the causes of IBR performance issues benefits ~~Buk Power System (~~BPS~~)~~ reliability by preventing recurrence. The CAP is an established tool for resolving operational problems. The NERC *Glossary* defines a Corrective Action Plan as, "A list of actions and an associated timetable for implementation to remedy a specific problem." Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the IBR Performance issue cause(s) is identified in Requirement R2 or Requirement R3 requires Generator Owner(s) to develop a CAP or provide a technical justification that addresses why corrective actions will not be applied nor implemented. The CAP is provided to the Reliability Coordinator, Balancing Authority, and Transmission Operator so that these entities 1) gain information potentially relevant to recent system events, and 2) can account for potential IBR performance issues in operational risk assessments.

This standard recognizes there may be multiple causes for IBR performance issues. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a ~~single or multiple~~ CAP~~(s)~~ to correct multiple causes of an IBR performance ~~issues~~issue. The 60-calendar day period for developing a CAP or technical justification is established based on industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent IBR performance issues from reoccurring, the timetable for executing such actions, and an evaluation of the CAP's applicability to the GO's other IBR including those at other locations. The evaluation of these other IBR with similar designs aims to reduce the risk and the likelihood of similar IBR performance issues in other IBRs. The GO is responsible for determining the extent of its evaluation concerning other IBRs and locations. The evaluation may result in the GO including actions to address IBR at other locations or to provide a technical justification that addresses why corrective actions will not be applied nor implemented.

Acceptable technical justification for not performing corrective actions is expected to primarily have two characteristics:

1) interconnection requirements on IBR performance extending beyond those in place at the time of interconnection; and

2) it would require significant material modifications/qualified change.

Technical justifications for not performing corrective actions do not relieve the GO from compliance ~~to~~with other standards (i.e., PRC-029-1 Ride-Through) to the extent that other standards are applicable.

Rationale for Requirement R4

Requirement R4 requires that each ~~entity~~applicable GO implement the CAP developed in Requirement R3, as applicable, to mitigate deficiencies identified in Requirement R2. In the NERC *Glossary*, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem."

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. If the CAP is changed, the entity must notify the applicable ~~RC~~Reliability Coordinator(s), ~~TOP~~Transmission Operator(s), or ~~BA~~Balancing Authority (s). The entity must also notify applicable RC(s) when the CAP has been completed. The implementation of a properly developed CAP ensures that causes of unexpected changes in IBR power output are mitigated in a timely manner.

An IBR deficiency may require the ~~RC~~Reliability Coordinator to impose operating restrictions so the system can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions should incentivize the entity to complete the CAP as quickly as possible.

Unofficial Comment Form

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

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on draft four of **PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation** by **8 p.m. Eastern, Friday, September 13, 2024.**

Additional information is available on the project page. If you have questions, contact Standards Developer, Josh Blume (email), or at 404-446-2593.

Background Information

Multiple NERC disturbance reports have identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that this undesired performance can pose. Project 2023-02 addresses the reliability-related need by requiring analysis and mitigation of unexpected or unwarranted protection and control operations from IBRs. This includes any types of protections and controls that result in abnormal performance issues within the plant, including abnormal performance resulting in anomalous behavior of active power output from the facility during events.

On October 19, 2023, FERC issued Order No. 901, which directed NERC to develop new or modify existing Reliability Standards that include new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. Project 2023-02 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 a waiver allowing formal comment periods to be reduced from 45 days to as few as 15 calendar days, and final ballot periods to be reduced from 10 days to as few as 5 calendar days in order to help meet the FERC- directed deadline.

Questions

1. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

   ☐ Yes
   ☐ No

   Comments:

2. Provide any additional comments for the Drafting Team to consider, if desired.

Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

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

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 Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues. 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 Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric 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 Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric 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 Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric 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 Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric 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 Electric System, or the ability to effectively monitor and control the Bulk Electric 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 Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric 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-030-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because not having a process for identifying changes in Real Power output, which is required in defining the minimum standards will be performed, could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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 medium 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-030-1, Requirement R1	
Proposed VRF	**Medium**
than One Obligation	

VSLs for PRC-030-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity failed to implement a documented process to identify changes in Real Power output in accordance with Requirement R1.

VSL Justifications for PRC-030-1, 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.
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-030-1, Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because a Generator Owner not analyzing it's Inverter Based Resource's performance which are required in defining the minimum standards will be within 90 days of an event, identified pursuant to Requirement R1 or receipt of a request pursuant to Requirement R2, to address the unexpected change(s) in power output and the applicability to its other IBR facilities that could be affected by the same cause of unexpected change(s) in power output could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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	This VRF is in line with the definition of a medium VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-030-1, Requirement R2	
Proposed VRF	**Medium**
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-030-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed an analysis in accordance with Requirement R2, but in more than 90 calendar days but less than 120 calendar days of an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 120 or more calendar days but less than 150 calendar days of an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 150 or more calendar days but less than 180 calendar days of an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 or Part 2.1.4. OR The responsible entity failed to provide the analysis results from the requesting entity in accordance with Requirement R2, Part 2.2.	The responsible entity developed an analysis in accordance with Requirement R2, but in 180 calendar days or more of an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 and Part 2.1.4. OR The responsible entity failed to document the facility's Ride-through performance in accordance with Requirement R2, Part 2.1.2 OR

			The responsible entity failed to determine the susceptibility of other inverter-based resource facilities in accordance with Requirement R2, Part 2.1.3.

VSL Justifications for PRC-030-1, 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 not 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	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for PRC-030-1, Requirement R2	
Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF Justifications for PRC-030-1, Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because a Generator Owner's failure to develop either a Corrective Action Plan (CAP), or technical justification that addresses why corrective actions will not be applied nor implemented for it's Inverter Based Resource's could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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 medium VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-030-1, Requirement R3	
Proposed VRF	**Medium**
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-030-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 60 days, but provided it within 90 days.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 90 days, but provided it within 120 days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 120 days, but provided it within 150 days OR The developed CAP did not include corrective actions for other facilities owned by the Generator Owners as identified in Requirement R2 Part 2.1.3, if necessary. OR The developed CAP or technical justification was not provided to the associated Reliability Coordinator, Balancing Authority,	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented, within 150 calendar days.

		and Transmission Operator.	

VSL Justifications for PRC-030-1, 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 not 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-030-1, Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because failure to implement, update, or notify with the applicable Reliability Coordinator (RC) the Corrective Action Plan (CAP) for it's Inverter Based Resource's could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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 medium 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-030-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R4.

VSL Justifications for PRC-030-1, 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 not 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-030-1, Requirement R4	
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.

Mapping Document
Consideration of FERC Order 901 Directives

Project 2023-02 Unexpected Inverter-Based Resource Event Mitigation
August 2024

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, there 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.

FERC Order 901 Directives	
Directive Language	**Consideration of Directives**
P58. 208 "Further, the Reliability Standards must require generator owners to communicate to the relevant planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities the actual post-disturbance ramp rates and the ramp rates to meet expected dispatch levels (i.e., generation-load balance)."	The Drafting Team addressed this directive in proposed PRC-030-1 through Requirements R1, R2, R3, and R4. Requirement R1 requires GOs to implement a documented process to identify any complete facility loss of output or certain changes in Real Power output. Requirement R1 also includes exclusions to these identification measures.

[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

	Requirement R2 requires that GOs, within 90 calendars of identifying a Real Power change under Requirement R1 or a request from the applicable RC, BA, or TOP that identified a Disturbance and change in IBR Real Power output, to analyze IBR facility performance during the event, and, provide the analysis results to the requesting applicable RC, BA, or TOP. Post event documentation for the GO's facilities using Ride-Through performance, including the ramp rate and reactive power response during the event, occurs in Requirement R2 Parts 2.1.1 and 2.1.3. Requirements R2 also gives the ability for communication from RC, BA, TOP to the GO requesting analysis results. Requirements R3 and R4 require the GO to develop a Corrective Action Plan (CAP), implement the CAP, and update the CAP if actions or timetables change. The GO will need to notify and provide the CAP, or the justification why no corrective actions are needed, to the applicable entity.

Standards Announcement

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

Formal Comment Period Open through September 13, 2024

Now Available

A 17-day formal comment period for draft four of **PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation** is open through **8 p.m. Eastern, Friday, September 13, 2024**.

This will be the last opportunity for NERC to ballot this project. This standard had minor changes from the last passing ballot. One change was in the Applicability section, removing "Elements associated with" from the Facilities section. The drafting team also made very minor changes, based on comments received, that were necessary. Another change for this posting is in regard to the PRC-030-1 Implementation Plan, to provide better clarity.

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.

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 **September 4-13, 2024**.

For 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 470-755-0346. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues 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:	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues | Draft 4
Comment Period Start Date:	8/28/2024
Comment Period End Date:	9/13/2024
Associated Ballots:	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Implementation Plan AB 4 OT 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues PRC-030-1 AB 4 ST

There were 45 sets of responses, including comments from approximately 129 different people from approximately 93 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

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
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	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
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Amber Skillern	East Kentucky Power Cooperative	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
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
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
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	
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	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 believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FE sees no alternative or more cost-effective options.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy does not normally respond to cost-effective questions and offers no alternatives to what has been proposed in PRC-030-1.	
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 MRO NSRF 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 offers no alternatives to what has been proposed in PRC-030-1.

Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	
Comment	

EEI offers no alternatives to what has been proposed in PRC-030-1

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	
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	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
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	No
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers

Answer	No
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	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	

Comment	
A more cost-effective way would be to let the Transmission Operator identify the events for which service data needs to be studied. Have the Generation Plants responsible for providing that data. Evaluating all potential events results in more work that may or may not provide benefit to the Bulk Power System.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	Yes
Document Name	
Comment	
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. Basically, what we are being asked to do is to analyze the cost and reliability benefits this proposal would provide without any data.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
The MRO NSRF does agree that inverter-based resources need identify, analyze, and mitigate unexpected changes of Real & Reactive Power output. However, it is not reasonable, practicable or cost effective to have Generator Owners analyze every change in Real Power output based on the magnitudes proposed in Requirement R1 even with the exclusions outlined in the proposed Requirement R1. The MRO NSRF strongly encourages the SDT to consider the process that will be required to demonstrate compliance with the proposed Requirement R1 and the amount of administration that will be required to verify whether a change in active power meets the criteria for analysis in the proposed Requirement R1. In addition, the MRO NSRF has offered more cost-effective alternatives for the SDT.	

- PRC-030-1, Requirement R1, Draft 4 still contains an overlap with NERC Reliability Standard PRC-004-6, Requirement R1. Further, the exclusionary bullet four assumes that a Misoperation has occurred. The MRO NSRF suggests the following update to PRC-030-1, Requirement R1, Bullet 4, which aligns with the language in PRC-004-6.

o Real Power reduction due solely to BES interrupting device operations being analyzed under NERC Reliability Standard PRC-004.

- PRC-030-1, Requirement R1, Draft 4. The MRO NSRF would like to reiterate that Requirement R1 “documented process to identify unexpected changes” is not a requirement within the SAR’s scope. According to the SAR, Generator Owners need to “analyze performance issues identified at their facilities”. Having a documented process is not in alignment with other performance analysis standards such as PRC-004-6, is administrative in nature without any reliability benefit and not cost-effective. The MRO NSRF suggest removing this requirement language in its entirety.

- PRC-030-1, Requirement R2, Draft 4, “90 calendar day”. As previously commented, the MRO NSRF does not agree with the 90 calendar day timeframe and believes it should be 120 days similar to PRC-004-6. Further, the SDT commented in the draft two responses the reason for maintaining the 90 calendar day timeframe was “to ensure diligence”, the MRO NSRF does not feel that this is an acceptable justification for maintaining a 90 calendar day timeframe.

PRC-030-1, Requirement R2, Draft 4. The MRO NSRF does not agree with allowing the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA) to be able to request an analysis of any a change in “the inverter-based resource(s) Real Power output”; the criteria for this analysis shall be the same criteria as outlined in Requirement R1.

- PRC-030-1, Requirement R3, Draft 4: The MRO NSRF would like to reiterate that being required to provide either a ‘Corrective Action Plan or justification of why corrective actions will not be applied to the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA)’ is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6, is administrative in nature without any reliability benefit and not cost effective. The MRO NSRF suggests the following language:

o “…and upon request provide it to the applicable associated Reliability Coordinator, Balancing Authority, and Transmission Operator:”

- PRC-030-1, Requirement R4.3, Draft 4. The MRO NSRF would like to reiterate that the proposed Requirement R4.3 is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6,

is administrative in nature without any reliability benefit and not cost-effective. In addition, the MRO NSRF does not understand why the Balancing Authority, and Transmission Operator are not included in the requirement language. The MRO NSRF suggests making requirement R4.3 contingent on requests made under Requirement R3. Essentially, a responsible entity only needs to provide external updates of the corrective actions plans to the requesting entity if those corrective actions plans were requested under Requirement R3.

Based on the aforementioned comments the MRO NSRF suggests combining Requirements R1 & R2 as follows:

R1. Each applicable Generator Owner, within 120 calendar days of 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 4 second period, or following a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the Inverter-Based Resource(s) Real Power output that are at least 20 MW and at least 10% of the plant's gross nameplate rating, occurring within a 4 second period, shall, 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 IBR generator; or

· Real Power reduction due solely to BES interrupting device operations being analyzed under NERC Reliability Standard PRC-004.

1.1. Analyze its IBR facility performance during the event, including:

1.1.1. Determine the root cause(s) of change(s) in Real Power output;

1.1.2. Document the facility's Ride-through performance including Reactive Power response during the event;

1.1.3. Assess any performance issues identified and if corrective actions are needed; and

1.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities.

1.2. Upon request, provide the analysis results to the requesting associated Reliability Coordinator, Balancing Authority, or Transmission Operator.

Likes 1	JEA, 1, McClung Joseph
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.	
Likes 0	
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	
Answer	Yes
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation supports NAGF comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
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 Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 1.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.	
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 MRO:

The MRO NSRF does agree that inverter-based resources need identify, analyze, and mitigate unexpected changes of Real & Reactive Power output. However, it is not reasonable, practicable or cost effective to have Generator Owners analyze every change in Real Power output based on the magnitudes proposed in Requirement R1 even with the exclusions outlined in the proposed Requirement R1. The MRO NSRF strongly encourages the SDT to consider the process that will be required to demonstrate compliance with the proposed Requirement R1 and the amount of administration that will be required to verify whether a change in active power meets the criteria for analysis in the proposed Requirement R1. In addition, the MRO NSRF has offered more cost-effective alternatives for the SDT.

- PRC-030-1, Requirement R1, Draft 4 still contains an overlap with NERC Reliability Standard PRC-004-6, Requirement R1. Further, the exclusionary bullet four assumes that a Misoperation has occurred. The MRO NSRF suggests the following update to PRC-030-1, Requirement R1, Bullet 4, which aligns with the language in PRC-004-6.

o Real Power reduction due solely to BES interrupting device operations being analyzed under NERC Reliability Standard PRC-004.

- PRC-030-1, Requirement R1, Draft 4. The MRO NSRF would like to reiterate that Requirement R1 “documented process to identify unexpected changes” is not a requirement within the SAR’s scope. According to the SAR, Generator Owners need to “analyze performance issues identified at their facilities”. Having a documented process is not in alignment with other performance analysis standards such as PRC-004-6, is administrative in nature without any reliability benefit and not cost-effective. The MRO NSRF suggest removing this requirement language in its entirety.

- PRC-030-1, Requirement R2, Draft 4, “90 calendar day”. As previously commented, the MRO NSRF does not agree with the 90 calendar day timeframe and believes it should be 120 days similar to PRC-004-6. Further, the SDT commented in the draft two responses the reason for maintaining the 90 calendar day timeframe was “to ensure diligence”, the MRO NSRF does not feel that this is an acceptable justification for maintaining a 90 calendar day timeframe.

PRC-030-1, Requirement R2, Draft 4. The MRO NSRF does not agree with allowing the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA) to be able to request an analysis of any a change in “the inverter-based resource(s) Real Power output”; the criteria for this analysis shall be the same criteria as outlined in Requirement R1.

- PRC-030-1, Requirement R3, Draft 4: The MRO NSRF would like to reiterate that being required to provide either a ‘Corrective Action Plan or justification of why corrective actions will not be applied to the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA)’ is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6, is administrative in nature without any reliability benefit and not cost effective. The MRO NSRF suggests the following language:

o “…and upon request provide it to the applicable associated Reliability Coordinator, Balancing Authority, and Transmission Operator:”

- PRC-030-1, Requirement R4.3, Draft 4. The MRO NSRF would like to reiterate that the proposed Requirement R4.3 is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6,

is administrative in nature without any reliability benefit and not cost-effective. In addition, the MRO NSRF does not understand why the Balancing Authority, and Transmission Operator are not included in the requirement language. The MRO NSRF suggests making requirement R4.3 contingent on requests made under Requirement R3. Essentially, a responsible entity only needs to provide external updates of the corrective actions plans to the requesting entity if those corrective actions plans were requested under Requirement R3.

Based on the aforementioned comments the MRO NSRF suggests combining Requirements R1 & R2 as follows:

R1. Each applicable Generator Owner, within 120 calendar days of 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 4 second period, or following a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the Inverter-Based Resource(s) Real Power output that are at least 20 MW and at least 10% of the plant's gross nameplate rating, occurring within a 4 second period, shall, 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 IBR generator; or

· Real Power reduction due solely to BES interrupting device operations being analyzed under NERC Reliability Standard PRC-004.

1.1. Analyze its IBR facility performance during the event, including:

1.1.1. Determine the root cause(s) of change(s) in Real Power output;

1.1.2. Document the facility’s Ride-through performance including Reactive Power response during the event;

1.1.3. Assess any performance issues identified and if corrective actions are needed; and

1.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities.

1.2. Upon request, provide the analysis results to the requesting associated Reliability Coordinator, Balancing Authority, or Transmission Operator.

Likes 0	
Dislikes 0	

Response

Michael Goggin - Grid Strategies LLC - 5

Answer	Yes
Document Name	

Comment

We are highly concerned that, relative to the first draft, the current draft of the standard reduces the threshold for output change events that must be reviewed to determine if they need to be analyzed. The revised standard sets the threshold at a change in output that is greater than 10% of the plant's nameplate rating (and greater than 20 MW) within 4 seconds, relative to the threshold of 20% within 2 seconds in the initial draft. This change only adds to our concerns about the generator owner's burden of manually reviewing each output change to exclude events caused by normal fluctuations in plant output due to weather, dispatch, and other factors. No mechanism exists for generator owners to automatically exclude those permissible changes from consideration. Wind and solar plants have a limited number of meteorological towers and pyranometers for measuring the available wind and solar resource, respectively, which makes it difficult in many cases to precisely determine whether changes in output across a plant were caused by resource availability.

The new lower threshold will pick up many more such events, as changes of 10% output within 4 seconds can routinely occur at solar and wind plants. As we explained in our previous comments, the passage of clouds over medium-sized solar plants can cause changes in output that are larger than this threshold.[1] As a result, in some cases a large share of the events a generator owner is required to review will be these normal changes in output, diverting their time and resources away from addressing real reliability concerns.

The drafting team's response to our comments in the first round of balloting only reinforces our concern about the burden imposed on the generator owner: "GOs would not know if it was unexpected behavior of generator settings and controls until the analysis is performed. The exceptions that have been moved from the footnote to the Standard Language allow for GOs to dismiss events due to cloud cover, change in wind speed. etc. Outage/Fault codes would be reviewed during the analysis process. It will be up to GOs to develop a process to identify events that that do not fit into the listed exclusions and require further analysis." It is highly burdensome for a generator owner to pull turbine- or inverter-level fault codes and plant-level fault codes for each event with a more than 10% change in output. Moreover, the drafting team cannot ignore the excessive and unworkable burden imposed on generator owners by simply dismissing that with "It will be up to GOs to develop a process to identify events that that do not fit into the listed exclusions and require further analysis."

As explained in our answer to question 2 below, the best solution to these concerns may be to remove most if not all of R1, and instead rely on analysis requests initiated by the Reliability Coordinator, Balancing Authority, or Transmission Operator following a disturbance event that causes a drop in generator output per R2.

Second, we are concerned that generator owners will be required to conduct a full analysis of all events in which an IBR plant reduces real power output to prioritize reactive power output, as is desirable and expected during voltage disturbances. The standard should be revised to include a mechanism to automatically screen out disturbance events in which the IBR generator briefly reduced real power output because it entered reactive power priority mode.

During a voltage disturbance on the bulk power system, the most helpful response is typically for generators to shift some of their power output from providing real power to prioritizing reactive power to help prevent voltage collapse.[2] As experts at the Energy Systems Integration Group (ESIG) explain, summarizing the conclusions of a recent workshop on generator interconnection, “If too much active power is injected into a point of interconnection with already depressed voltage, it may further collapse the voltage, causing more cascading outages and compromising the reliability of the grid. Rather than keeping the active power of an IBR at a pre-disturbance level, it is more beneficial to reduce active power, depending on severity of voltage drop thus preventing further voltage collapse — while reactive power is prioritized and increased to support grid and terminal voltage.”[3]

Not only does a requirement to maintain active power production instead of prioritizing reactive power production during a voltage disturbance risk exacerbating voltage collapse, but it is also infeasible in many cases. If the voltage is low during and following a disturbance, even if an IBR plant continues to inject its full pre-disturbance level of active current, it cannot maintain the level of active power it was delivering because voltage is now lower and active power is the product of voltage and current. Moreover, to increase reactive power injection, a generator must typically shift its output away from active power injection (power is comprised of active and reactive components). Both synchronous and asynchronous generators have a finite ability to produce power, so they must reduce real power (P) production to increase reactive power (Q) along the P-Q generator capability curve.[4] In most cases, it is infeasible for any type of generator to maintain active power production while also increasing reactive power output during a disturbance.

Solutions

To address the concerns expressed in our answer to question 1 above regarding the burden on generators of screening out changes in output that are not caused by disturbances, the best solution may be to remove most if not all of R1, and instead rely on analysis requests initiated by the Reliability Coordinator, Balancing Authority, or Transmission Operator following a disturbance event per R2. This would remove the inefficient “needle in the haystack” burden on generators under R1 to screen every output change event to find the small subset that are due to disturbances, and instead only focus resources on reviewing significant disturbance events that coincided with a change in generator output. Because many generators do not have synchrophasors or other equipment required to determine when significant grid disturbances have occurred, it makes more sense for the analysis to be initiated by a request from the RC, BA, or TO. Relatedly, we reiterate our request from the first comment period to add a requirement to R2 that the RC, BA, or TO must file its request within 15 days of the disturbance event. This will ensure that the GO has at least five days to pull data before it is overwritten, given that the data retention period in the current draft of PRC-028 R7 is 20 days.

As explained above, the standard should also be revised to include a mechanism to exclude analysis of disturbance events in which the IBR generator briefly reduced real power output because it entered reactive power priority mode.

Finally, the requirement on the generator owner in 2.1.4 to “Determine the applicability of the root cause(s) to the Generator Owner’s other Inverter-Based Resource facilities” appears to be unreasonable if not unworkable. A company that owns multiple IBR plants typically uses different equipment and settings across its plants, and some may be wind plants while others are solar plants, so there is no reason to assume its other plants have the same susceptibility simply because they have the same owner. At minimum, the requirement should be clarified to specify whether projects owned by the same parent company but that are incorporated as separate LLCs must be assessed as part of compliance with 2.1.4., and other such details.

{C}[1]{C} https://www.sciencedirect.com/science/article/abs/pii/S0306261917300144

{C}[2] https://www.esig.energy/download/interconnection-requirements-need-for-harmonization-jason-macdowell/?wpdmdl=9267&refresh=62f587eab15591660258282, at 6

{C}[3]{C} https://www.esig.energy/wp-content/uploads/2022/10/Joint-Generator-Workshop-Summary-1.pdf, at 29

{C}[4] See Figure 4 for an example of a synchronous generator's P-Q curve and Figure 5 for a non-synchronous generator's P-Q curve: https://link.springer.com/article/10.1007/s40565-019-0535-4

Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
As currently drafted, Invenergy believes PRC-030-1 imposes a significant resource burden on GOs without commensurate benefit to reliability. GOs will need to dedicate significant resources to identify, analyze, and validate events that may pose no reliability concern. Invenergy understands that regional entities may not have the ability to identify single plant performance issues, but they would be able to identify events that have a system-level impact, at which point the GO could be instructed to provide greater analysis of its performance during that specific time period.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	

PRC-030-1 imposes a significant resource burden on GOs without commensurate benefit to reliability. GOs will need to dedicate significant resources to identify, analyze, and validate events that may pose no reliability concern. Invenergy understands that regional entities may not have the ability to identify single plant performance issues, but they would be able to identify events that have a system-level impact, at which point the GO could be instructed to provide greater analysis of its performance during that specific time period.

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

It is the opinion of ACES that PRC-030-1 Requirement R1 should be more aligned with PRC-004-6 Requirement R1. In short, we believe that requiring a documented process to identify applicable events at an IBR, as is currently required by PRC-030-1 R1, increases the compliance burden for the GO with no appreciable decrease in the risk to the BPS. Therefore, we recommend striking the phrase “implement a documented process to” from PRC-030-1 Requirement R1. The revised version of R1 would thus read as follows:

R1. Each applicable Generator Owner shall 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 4 second period. 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 IBR generator; or
- Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.

Secondly, ACES does not agree with the removal of the word “identifying” from Requirement R2. It is the opinion of ACES that removing this word places an undue burden on the GO to perform the analysis within an unnecessarily compressed timeline. While it is still our opinion that a timeline of 120 days is more appropriate as it is more consistent with PRC-004-6; we do not see it as an insurmountable hurdle to require a 90 calendar-day timeline so long as it begins when the GO identifies the event. Thus, we recommend modifying R2 as follows:

R2. Each applicable Generator Owner shall perform the activities identified in each subpart of this Requirement, within 90 calendar days, of either:

- identifying a Real Power change event pursuant to Requirement R1 or,
- receiving a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator wherein the requesting entity identified an event meeting the thresholds established in Requirement R1

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in Real Power output;

2.1.2. Document the facility’s Ride-through performance including Reactive Power response during the event;

2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities.

2.2. Upon request, provide the analysis results to the requesting associated Reliability Coordinator, Balancing Authority, or Transmission Operator.

Furthermore, it is the opinion of ACES that the GO should not be required to submit a CAP to the RC, BA, nor TOP. This is not in line with the requirements identified in PRC-004-6 Requirement R6 nor does it add any appreciable reduction in risk while at the same time increasing the compliance burden for the GO and likely the RC, BA, and/or TOP. In other words, why should the GO submit its CAP to these entities if they are not required to perform any action(s) upon receipt (or even acknowledge receipt)? In short, if the RC, BA, or TOP desires an opportunity to review the CAP(s) developed by the GO, there is already a mechanism in place for this via the documented data specification(s).

Lastly, requirements R3 and R4 of the proposed PRC-030-1 do not align with one another. For example, as written, R3 requires a CAP be provided to the RC, BA, and TOP whereas R4 Part 4.3 only requires that the RC be notified. We recommend modifying these sections so that they are inline with one another. In other words, either require the GO to notify the RC, BA, and TOP in R4 Part 4.3 or remove the BA and TOP from Requirement R3.

Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
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	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	

Answer	
Document Name	

Comment

No Comment

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

ITC has no 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 will not comment on cost effectiveness.

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	
Document Name	

Comment	
No comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	

2. Provide any additional comments for the Drafting Team to consider, if desired.

Amy Wilke - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
ATC had not initially joined the ballot pool for this standard as it was not directly applicable to TO/TOP, however, we would like to express our support of the standard as written and thank the team for their effort.	
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	

Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	
Document Name	
Comment	
NRG is in alignment with NAGF's comments	
Likes 0	
Dislikes 0	
Response	

Usama Tahir - Seminole Electric Cooperative, Inc. - 3	
Answer	
Document Name	
Comment	

1. If a device can impact a plants gross nameplate rating by 10% or 20 megawatts respectively, does that Cyber Asset now become CIP applicable? I.e., what impact to CIP will this have if the measure of detriment is 20 MW or 10% of a total unit? Can the Standard Drafting Team add color to this question?
2. Take for instance a site that has both PV and BESS. The PV has a gross nameplate of 74.5 MW. The BESS has a gross nameplate of 30 MW. However, the site is synthetically limited to 74.5 MW, i.e., the output cannot exceed 74.5 MW. Would the Generator Owner still need to use the gross nameplate rating of the combined generators or can the 20 MW/10% value be calculated off of any synthetically limited value?
3. GO should have a time period of 120 days in R2 after identification of R1 events and 120 days to complete R3, to be consistent with PRC-004 Requirements. This will give entities a chance to determine which Standard to apply to an event.]
4. R4.3 reporting requirements should be consistent with PRC-004 R6. PRC-004-6 R6 does not require notification every time a CAP changes. The Standard Drafting team should mirror this language or add context into the technical guidance that describes why reporting should differ.
5. The Standard Drafting team should identify which elements to evaluate as requiring a CAP (i.e. elements that are directly responsible for the ride-through capabilities of an IBR).

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	

Bret Galbraith - Seminole Electric Cooperative, Inc. - 6	
Answer	
Document Name	
Comment	

1. If a device can impact a plants gross nameplate rating by 10% or 20 megawatts respectively, does that Cyber Asset now become CIP applicable? I.e., what impact to CIP will this have if the measure of detriment is 20 MW or 10% of a total unit? Can the Standard Drafting Team add color to this question?

2. Take for instance a site that has both PV and BESS. The PV has a gross nameplate of 74.5 MW. The BESS has a gross nameplate of 30 MW. However, the site is synthetically limited to 74.5 MW, i.e., the output cannot exceed 74.5 MW. Would Seminole still need to use the gross nameplate rating of the combined generators or can the 20 MW/10% value be calculated off of any synthetically limited value?
3. GO should have a time period of 120 days in R2 after identification of R1 events and 120 days to complete R3, to be consistent with PRC-004 Requirements. This will give entities a chance to determine which Standard to apply to an event.]
4. R4.3 reporting requirements should be consistent with PRC-004 R6. PRC-004-6 R6 does not require notification every time a CAP changes. The Standard Drafting team should mirror this language or add context into the technical guidance that describes why reporting should differ.
5. The Standard Drafting team should identify which elements to evaluate as requiring a CAP (i.e. elements that are directly responsible for the ride-through capabilities of an IBR).

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

Colin Chilcoat - Invenergy LLC - 6

Answer	
Document Name	

Comment

Thank you for the opportunity to provide comments.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	

Document Name	
Comment	

ERCOT supports modifying the criteria in Requirement R1 to 20 MW ***OR*** 10% instead of 20 MW **AND** 10%. Inverters/wind turbines/etc. will typically be 1-3 MW in size (with newer technologies approaching 4-5 MW). 10% of a 500 MW facility would be 50 MW and 10% of a 1,000 MW facility would be 100 MW (both of which are present and growing in new interconnection queues), which are excessive thresholds. One approach to address this issue would be to set both a floor and a ceiling by establishing a threshold of 20 MW **AND** 10% for IBRs with a nameplate capacity of less than 200 MW nameplate and to set a threshold of 20 MW **OR** 10% for IBRs with a nameplate capacity greater than or equal to 200 MW.

ERCOT recommends modifying the third bullet of R1 to be "• A Transmission or collection system loss that***, through normal clearing***, disconnects the IBR generator;" which would better align with the language used in other locations in the standards that describe normal clearing of faults.

ERCOT recommends that the reporting requirement in Requirement R2 be expanded to include a report to the RC, BA, and TO within three business days of the identification of an event. Although a GO/GOP may not have had adequate time to fully assess and analyze the incident at that point, the degree of the unexpected operation may pose significant risk that an operator may need to be aware of for situational awareness. The operator may have seen an impact on the system that could not be explained without this information. A follow-up report when the incident is fully assessed would still be communicated to the operator(s) for any longer-term considerations.

Finally, in light of FERC's directives in its *Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification*, and in light of modifications made by the PRC-029 SDT, ERCOT believes that NERC should be a part of the review process for any instances in which a GO does not implement a CAP as provided in the 2nd bullet of Requirement R3. For informational purposes, the pertinent language from FERC's Order is provided below (emphasis added).

33. Under Reliability Standard EOP-012-1, a generator owner could explain in a declaration any "technical, commercial, or operational constraints" that preclude its ability to either implement freeze protection measures or implement corrective action plans. However, Reliability Standard EOP-012-1 ***does not define "technical, commercial, or operational constraints," leaving those terms open to interpretation by each generator owner***. In the February 2023 Order, the Commission approved Reliability Standard EOP-012-1 but ***expressed concern with the uncertainties, ambiguities, and vagueness of the Standard's descriptions of constraints, noting that, without criteria to guide the generator owners or guardrails on what constitutes a legitimate constraint, generator owners may avoid the purpose of the Standard altogether or have declarations without auditable elements***. Thus, the ***Commission directed NERC to address the ambiguity of generator owner-defined declarations by including auditable criteria to ensure that declarations cannot be used to avoid mandatory compliance with the Reliability Standard or obligations in a corrective action plan***.

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 Standard Drafting Team's actions to change the Section 4, Applicability language to match that in the proposed PRC-028-1 and PRC-030-1 reliability standards. Although time is short to make further changes, the following improvements should be considered by this Standard Drafting Team or a future Team to enhance PRC-030-1.

1) PRC-030-1, Requirement R1, Draft 4 still contains an overlap with NERC Reliability Standard PRC-004-6, Requirement R1. The exclusionary bullet four assumes that a Misoperation has occurred and does not leave room for correct operations of protection systems. This would create an unnecessary burden on registered entities to create compliance documentation for both PRC-004 and PRC-030 for the same event caused by the correct operation of a protection system. We agree with the recommendation provided by the MRO NSRF to revise the bullet four language to the following and remove the overlap:

"Real Power reduction due solely to BES interrupting device operations being analyzed under NERC Reliability Standard PRC-004."

2) PRC-030-1, Requirement R2, Draft 4, "90 calendar day". SMUD does not agree with the 90 calendar day timeframe and believes it should be 120 days similar to PRC-004-6.

Likes 0	
Dislikes 0	

Response

Patricia Ireland - DTE Energy - 4, Group Name DTE Energy

Answer	
Document Name	

Comment

The PRC-030 standard language (Applicability Section 4.2.2) needs to align to Project 2020-06 for defining the term that will represent Category 2 IBRs

Similarly, the PRC-030 Implementation plan (footnote 8 on page 3 and the term definition for "applicable non-BES IBRs" used on Page 4) needs to align to Project 2020-06 definition of the Category 2 BES

Likes 0	
Dislikes 0	

Response

Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC

Answer	
Document Name	

Comment

Kindly suggest greater consideration of the standard drafting team to take in consideration therecommendations made by OEM and GO/GOP of existing IBRs on capabilities vs reliabiliaty improvement vs cost, from previous and current commenting.

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

SRP supports the standard but would like to see the 90 day portion of R2 reduced to 7 days. In order to ensure impacts to the BES are minimized, it seems important to define root causes to determine if an IBR can be safely returned to service or if mitigations need to be prepared if returned to service, or if the IBR needs to be kept on forced outage until mitigated. As we become more and more dependent on this type of resource for load serving and regulating needs this level of urgency is warranted in our opinion.

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	
Document Name	

Comment

R1 requirements
The technical rationale states that criteria for triggering analysis were chosen with the intention of screening out “small active power changes” while being low enough to detects events that present a reliability risk. The DT points to 3 studies performed at solar and wind facilities in Texas where wind speed and solar irradiance changes did not result in greater than a 20mw or 10% nameplate rating Real Power output ? in a 4 second window. These studies ranged from 1 month to 1 year, and 160MW-500MW nameplate ratings. Many factors can affect both the Real Power output, as well as the Power rate of change for IBR’s, particularly solar, where temperature, latitude, elevation, humidity, asset age, and geographical features, can all impact the effective output and how fast it may change based on disturbances to its energy source. These studies may provide insufficient data to draw wide conclusions about what changes in Real Power output due are likely for a given ? across the entire North American footprint, as the data is limited to a relatively narrow geographical location, number of facilities, and timeframe. Region-specific studies with more robust data would inspire confidence these changes do not present an undue burden in the way of nuisance event analysis.
R2 & R3 requirements
The time periods in R2 and R3 should be increased to 120 calendar days to allow time to determine the root cause and develop a Corrective Action Plan, especially if OEM support is required.
The stated rationale for the discrepancy between the PRC-004 analysis requirement of 120 days and the proposed PRC-030 requirement of 90 days is

that: “The PRC-004 timeframe accounts for extreme weather events such as hurricanes that may affect a very large number of Protection Systems for a given responsible entity”. Additionally it is stated that: “The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed”
The same extreme weather events that cause numerous PS operations can, and may even likely occur at the same time that unexpected output events occur for IBRs. Typically, it will be the same teams that analyze both of these types of events.
Furthermore, it is unclear on what basis the SDT has determined that 90 days allows sufficient time to provide thorough IBR response analysis as no evidence is presented. IBR proprietary control systems remain a major obstacle to analysis, and will necessitate communication with external vendors which are not bound by the compliance timeframe requirements of the PRC.
The same issues regarding control systems and external vendors will also exist for developing CAPs.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	
Document Name	

Comment

WEC Energy Group supports the comments of the MRO NSRF and 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

The NAGF has identified several concerns regarding the proposed revisions:

1. *Substantive change in Requirement R2: The removal of the word "identifying" in relation to the 90-day timeline for real power change events was seen as a significant change that could shorten the response time for entities. Therefore, the NAGF recommends removing the proposed wording change and leaving the language as is from PRC-030 Draft #3 that was approved by industry.*
2. *Inconsistency between R3 and R4: R3 requires the Corrective Action Plan (CAP) to be provided to the RC, BA, and TOP, while R4 only mentions the RC. This inconsistency was noted as potentially problematic.*

3. *VSL terminology: The continued use of the term "susceptibility" in the Violation Severity Levels (VSLs) was highlighted, despite its removal in previous versions of the standard.*
4. *Implementation plan changes: The removal of a paragraph linking PRC-30 to PRC-29 in the implementation plan was seen as a significant change that could impact the sequential implementation of these standards.*
5. *Lack of clarity on actions required: There was uncertainty about what actions the RC, BA, and TOP need to take upon receiving the CAP.*

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment

Constellation thinks "Nameplate rating" needs to be clarified as they are many ways to define that especially for solar and storage plant. Recommend adding "at the Point of Interconnection as defined in the interconnection agreement" in R1. Further, athough the analysis completion was changed from 45 days to 90 days in R1. Timeframe needs to be adjusted to 120 days to match PRC-004 .

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

Duke Energy agrees with and suggest implementation of NAGF comments #1, #3 and #4 identified below:

#1: Substantive change in Requirement R2: The removal of the word "identifying" in relation to the 90-day timeline for real power change events was seen as a significant change that could shorten the response time for entities. Therefore, the NAGF recommends removing the proposed wording change and leaving the language as is from PRC-030 Draft #3 that was approved by industry.

#3: VSL terminology: The continued use of the term "susceptibility" in the Violation Severity Levels (VSLs) was highlighted, despite its removal in previous versions of the standard.

#4: Implementation plan changes: The removal of a paragraph linking PRC-30 to PRC-29 in the implementation plan was seen as a significant change that could impact the sequential implementation of these standards. Additionally, Duke Energy notes that PRC-030 is dependent on data from PRC-028.	
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 and supports NAGF comments. In addition, Black Hills Corporation is concerned with the standard not defining a time frame for RC, BA, or TO to notify GO of a disturbance. Black Hills Corporation's current practice is to maintain a rolling year's worth of data, it is unclear if this would be sufficient for compliance with the standard.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
1) Shouldn't another bullet be added in the exclusion list in R1? · Real Power reduction due solely to a RAS (Remedial Action Scheme) Misoperations being analyzed and corrected under PRC-012 Reliability Standard	
Likes 0	
Dislikes 0	
Response	

Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	
Comment	
Substantive change in R2 - Standard (1st screenshot) has been updated to remove "identifying" from R2. By making this change the 90 day timeline is effectively shortened during which entities have to analyze the event, because entities will not be able to "identify" events in real time. Implementation plan changes: The removal of a paragraph linking PRC-30 to PRC-29 in the implementation plan was seen as a significant change that could impact the sequential implementation of these standards. Lack of clarity on actions required: There was uncertainty about what actions the RC, BA, and TOP need to take upon receiving the CAP.	
Likes 0	
Dislikes 0	
Response	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	
Comment	
The MRO NSRF thanks the SDT for consideration of these and previous comments.	
Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
If BAs, RCs, and TOPs needed this data then they have had years to request it via their interconnection agreements and market rules.	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
Requirement R3 mandates that all CAPs or justifications from “performance issues and corrective actions [that] were identified in Requirement R2 Part 2.1.3” be provided “to the applicable RC, BA, and TOp”. However, not all issues and actions from Requirement R2 were identified or communicated to the GO from the RC, BA, or TOp. As such, only the ones coming from the RC, BA, or TOp should have to be provided back to them and then, only to the one(s) that provided it to the GO, not necessarily to all three. Similar comment to Requirement R4.3 - only the CAP actions resulting from a notification from the RC should have to be reported back to the RC. Also, what about the CAP actions resulting from a BA or TOp notification - shouldn’t they be communicated back to them?	
Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	

AEP would like to thank the SDT for revising R2 to make it clear that the expectations are within 90 days of the event itself, and for replacing the word “applicable” with “associated” throughout the standard in regards to the Functional Entities.

On the previous ballot period, the SDT responded to AEP by stating “In the case where a root cause cannot be identified, this would conclude the analysis portion of Requirement R2. However, ***mitigating actions should be implemented*** so that a root cause can be determined for subsequent events, such as correcting inverter logs and insufficient data capture.” While AEP agrees in principle that doing so would be a reasonable approach, we do not believe the standard obligations themselves clearly convey such expectations, as this language is not included in the standard nor insight provided within the Technical Rationale. This language needs to be explicitly included in the standard, so that it is fully understood and consistently executed by Functional Entities. In addition, the standard could be further improved by revising it to accommodate for situations when a cause is found, but where an entity is unable to fully mitigate it.

Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	

FirstEnergy continues to request clarification on the determination of what would be a failure vs. weather as related to Requirement 1.
FirstEnergy would request an expansion of the threshold criteria that would fall under PRC-030-1, understanding the scan rate is able to detect these changes, these minor occurrences and investigations potentially take the primary focus away from the protection of the BES.

Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	
Document Name	

Comment

WECC voted affirmative but offers the following for consideration.

Standard comments- Consider spelling out Inverter-Based Resource in the third bullet of Requirement 1 that currently is just "IBR" to be consistent with other Requirements. Consider capitalizing "inverter-based resource" in Requirement R2 Severe VSL. Requirement R3 Lower, Moderate, and High VSLs need to reflect "calendar days" to match the Requirement language (and the Severe VSL language)

Implementation Plan comments-The title of Standard PRC-029 is not correct (should be "PRC-029-1 Frequency and Voltage Ride-through Requirements for Inverter-Based Resources"). In the "Background" section first sentence there is a need to update "inverter-based resources (IBR)" and replace the added "Inverter-Based Resources (IBR)" with simply "IBRs". Determine if a hyphen is needed or not for "BPS-connected" as both are used. Need to lower case the "s" in "IBRS" in the last sentence of "General Considerations". Footnote 8 needs edited to remove the first "as" between "such" and "IBRs". Need to lower case the "s" in "IBRS" in the sentence under "Bulk-Electric System IBRs" header. Although allowed, consider consistency in use of "Bulk Electric System" or "Bulk-Electric System" especially when sitting next to each other in document. Suggest simply use "BES IBRs" as the header and the first part of sentence under the "Bulk-Electric System IBRs" header. Consider removal of "Applicable" for the "Applicable Non-BES IBRs" header as it is unnecessary. The definition provides what a Non-BES IBR may be and a Standard would determine the applicability. If the DT thinks "applicable" is necessary, why is it not a modifier for "Bulk-Electric System IBRs" section?

It is not clear what the last sentence under the header "Applicable Non-BES IBRs" provides. Note the first part of the sentence (if retained as is) needs corrected to "Applicable Non-BES Inverter-Based Resources." It should be noted within the Implementation Plan and/or Technical Rationale that the Non-BES IBR definition reflects the ROP definition for Category 2 (and does not capitalize "inverter-based resource".) Now, with the "Applicable" modifier, the sentence reads as if there **are more** Non-BES Inverter-Based Resources that are included in the Phased-in Compliance considerations. Suggest removal of "Applicable" and the last sentence. If not, then the DT needs to explain what other "Applicable Non-BES IBRs" are outside of the defined Non-BES IBRs. There is a SAR that is considering "IBR-DER", "Sub-BES IBR", and "Non-Material IBR" definitions but that is in early stages of consensus building.

Likes 0	
Dislikes 0	

Response

Brian Lindsey - Entergy - 1

Answer	
Document Name	

Comment

Implementation Plan:

This is not a phased in implementation plan. Also, Entergy is concerned that the implementation of PRC-030 is dependent on the implementation of PRC-029 which has not been approved yet.

The implementation plan should be 365 days instead of 90 days to allow for any control changes that might be required. A process may need to be added to allow extensions of implementation based on potential supply chain issues.

Requirements:

R2. Data quality concern in an event happening in 4 seconds and being able to complete the analysis.

Concerns with having to provide the information to multiple entities.

R3 & R4. The reporting requirement should be synchronized with R3 and R4. Corrective plans should be intended for internal use only and not necessary to be reported out to other entities. What is the need and useability of that information to those entities?

The action to create the Corrective Action Plan should 90 days instead of 60 days. Recommend adding language in R3 that states that if all actions are completed during the analysis phase to correct the issue there will be no need for a CAP.

Likes 0	
Dislikes 0	

Response

Consideration of Comments

Project Name:	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues | Draft 4
Comment Period Start Date:	8/28/2024
Comment Period End Date:	9/13/2024
Associated Ballot(s):	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Implementation Plan AB 4 OT 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues PRC-030-1 AB 4 ST

There were 45 sets of responses, including comments from approximately 129 different people from approximately 93 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 Jamie Calderon (via email) or at (404) 446-9647.

Questions

1. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

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
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	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
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Amber Skillern	East Kentucky Power Cooperative	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
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
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
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

Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	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 believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FE sees no alternative or more cost-effective options.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	

Answer	No
Document Name	
Comment	
Duke Energy does not normally respond to cost-effective questions and offers no alternatives to what has been proposed in PRC-030-1.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
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 MRO NSRF and the NAGF.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to the MRO NSRF and NAGF.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI offers no alternatives to what has been proposed in PRC-030-1.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
EEI offers no alternatives to what has been proposed in PRC-030-1	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
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 for the comment and support.	
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	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
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	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the 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	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
A more cost-effective way would be to let the Transmission Operator identify the events for which service data needs to be studied. Have the Generation Plants responsible for providing that data. Evaluating all potential events results in more work that may or may not provide benefit to the Bulk Power System.	
Likes 0	
Dislikes 0	

Response	
The purpose of the SAR for Project 2023-02 is to have GOs self-identify events and investigate performance, the DT felt this is the best course forward to ensure reliability. The SAR notes, "It is important that the GO is accountable for analyzing these events, has necessary monitoring equipment installed, and cooperates with the BA/RC by providing operational data and analytical results. The past few NERC disturbance reports have highlighted limited awareness and understanding by facility owners that abnormal performance has even occurred, and therefore identification of possible performance issues should be initiated by either the IBR facility owner/operator (i.e., the GO/GOP) or by the transmission entities with a wide-area view (i.e., the TOP, RC, or BA). However, the onus of analysis and development of mitigating actions should be on the asset owner to eliminate the possible risk of repeated abnormal performance issues."	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	Yes
Document Name	
Comment	
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. Basically, what we are being asked to do is to analyze the cost and reliability benefits this proposal would provide without any data.	
Likes 0	
Dislikes 0	
Response	
The Project 2023-02 SAR didn't direct the Drafting Team to develop a cost analysis for the development of this standard. The Drafting Team developed the standard to provide the reliability benefits intended by the SAR.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	

Answer	Yes
Document Name	
Comment	

The MRO NSRF does agree that inverter-based resources need to identify, analyze, and mitigate unexpected changes of Real & Reactive Power output. However, it is not reasonable, practicable or cost effective to have Generator Owners analyze every change in Real Power output based on the magnitudes proposed in Requirement R1 even with the exclusions outlined in the proposed Requirement R1. The MRO NSRF strongly encourages the SDT to consider the process that will be required to demonstrate compliance with the proposed Requirement R1 and the amount of administration that will be required to verify whether a change in active power meets the criteria for analysis in the proposed Requirement R1. In addition, the MRO NSRF has offered more cost-effective alternatives for the SDT.

- PRC-030-1, Requirement R1, Draft 4 still contains an overlap with NERC Reliability Standard PRC-004-6, Requirement R1. Further, the exclusionary bullet four assumes that a Misoperation has occurred. The MRO NSRF suggests the following update to PRC-030-1, Requirement R1, Bullet 4, which aligns with the language in PRC-004-6.

o Real Power reduction due solely to BES interrupting device operations being analyzed under NERC Reliability Standard PRC-004.

- PRC-030-1, Requirement R1, Draft 4. The MRO NSRF would like to reiterate that Requirement R1 “documented process to identify unexpected changes” is not a requirement within the SAR’s scope. According to the SAR, Generator Owners need to “analyze performance issues identified at their facilities”. Having a documented process is not in alignment with other performance analysis standards such as PRC-004-6, is administrative in nature without any reliability benefit and not cost-effective. The MRO NSRF suggest removing this requirement language in its entirety.

- PRC-030-1, Requirement R2, Draft 4, “90 calendar day”. As previously commented, the MRO NSRF does not agree with the 90 calendar day timeframe and believes it should be 120 days similar to PRC-004-6. Further, the SDT commented in the draft two responses the reason for maintaining the 90 calendar day timeframe was “to ensure diligence”, the MRO NSRF does not feel that this is an acceptable justification for maintaining a 90 calendar day timeframe.

PRC-030-1, Requirement R2, Draft 4. The MRO NSRF does not agree with allowing the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA) to be able to request an analysis of any a change in “the inverter-based resource(s) Real Power output”; the criteria for this analysis shall be the same criteria as outlined in Requirement R1.

- PRC-030-1, Requirement R3, Draft 4: The MRO NSRF would like to reiterate that being required to provide either a ‘Corrective Action Plan or justification of why corrective actions will not be applied to the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA)’ is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6, is administrative in nature without any reliability benefit and not cost effective. The MRO NSRF suggests the following language:

o “…and upon request provide it to the applicable associated Reliability Coordinator, Balancing Authority, and Transmission Operator:”

- PRC-030-1, Requirement R4.3, Draft 4. The MRO NSRF would like to reiterate that the proposed Requirement R4.3 is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6,

is administrative in nature without any reliability benefit and not cost-effective. In addition, the MRO NSRF does not understand why the Balancing Authority, and Transmission Operator are not included in the requirement language. The MRO NSRF suggests making requirement R4.3 contingent on requests made under Requirement R3. Essentially, a responsible entity only needs to provide external updates of the corrective actions plans to the requesting entity if those corrective actions plans were requested under Requirement R3.

Based on the aforementioned comments the MRO NSRF suggests combining Requirements R1 & R2 as follows:

R1. Each applicable Generator Owner, within 120 calendar days of 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 4 second period, or following a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the Inverter-Based Resource(s) Real Power output that are at least 20 MW and at least 10% of the plant's gross nameplate rating, occurring within a 4 second period, shall, 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 IBR generator; or

· Real Power reduction due solely to BES interrupting device operations being analyzed under NERC Reliability Standard PRC-004.

1.1. Analyze its IBR facility performance during the event, including:

1.1.1. Determine the root cause(s) of change(s) in Real Power output;

1.1.2. Document the facility’s Ride-through performance including Reactive Power response during the event;

1.1.3. Assess any performance issues identified and if corrective actions are needed; and

1.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities.

1.2. Upon request, provide the analysis results to the requesting associated Reliability Coordinator, Balancing Authority, or Transmission Operator.

Likes 1	JEA, 1, McClung Joseph
Dislikes 0	

Response

Thank you for your comments. The DT exempted Protection System Misoperations from the Requirement R1 determination however correct operations of Protection Systems need to be analyzed to verify Ride-through performance requirements.

The DT reviewed the suggestion to eliminate the process requirement however kept it because it is an important element to ensure a process is in place that could adequately capture events. The documented process requirement can be found in other Reliability Standards such as CIP-003, CIP-004, CIP-005, and PRC-012.

The DT reviewed the suggestion and considered increasing the time however is holding to 90 days to ensure analyzing and correcting unexpected performance is a focus for the GO. The 120-day timeframe in PRC-004 was intended to cover a broad array of operations due to wide scale weather events such as hurricanes.

The thresholds only catch a subset of events that pose a risk to the system stability. The RC, BA, TOP require the ability to direct GOs to analyze other events that pose risks to the system.

The RC, BA and TOP are ultimately responsible for the operation and security of the BES and BPS. As such they are accountable to know and understand the limitations and issues in the electric system, requiring knowledge of respective Corrective Action Plans.

Ruchi Shah - AES - AES Corporation - 5

Answer	Yes
Document Name	
Comment	
GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
George E Brown - Pattern Operators LP - 5	
Answer	Yes
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to the MRO NSRF comment.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	

Constellation supports NAGF comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
Please see the DT's response to the NAGF comment.	
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 Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 1.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to the MRO NSRF comment.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to the MRO NSRF comment.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
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 MRO: The MRO NSRF does agree that inverter-based resources need to identify, analyze, and mitigate unexpected changes of Real & Reactive Power output. However, it is not reasonable, practicable or cost effective to have Generator Owners analyze every change in Real Power	

output based on the magnitudes proposed in Requirement R1 even with the exclusions outlined in the proposed Requirement R1. The MRO NSRF strongly encourages the SDT to consider the process that will be required to demonstrate compliance with the proposed Requirement R1 and the amount of administration that will be required to verify whether a change in active power meets the criteria for analysis in the proposed Requirement R1. In addition, the MRO NSRF has offered more cost-effective alternatives for the SDT.

- PRC-030-1, Requirement R1, Draft 4 still contains an overlap with NERC Reliability Standard PRC-004-6, Requirement R1. Further, the exclusionary bullet four assumes that a Misoperation has occurred. The MRO NSRF suggests the following update to PRC-030-1, Requirement R1, Bullet 4, which aligns with the language in PRC-004-6.

o Real Power reduction due solely to BES interrupting device operations being analyzed under NERC Reliability Standard PRC-004.

- PRC-030-1, Requirement R1, Draft 4. The MRO NSRF would like to reiterate that Requirement R1 "documented process to identify unexpected changes" is not a requirement within the SAR's scope. According to the SAR, Generator Owners need to "analyze performance issues identified at their facilities". Having a documented process is not in alignment with other performance analysis standards such as PRC-004-6, is administrative in nature without any reliability benefit and not cost-effective. The MRO NSRF suggest removing this requirement language in its entirety.

- PRC-030-1, Requirement R2, Draft 4, "90 calendar day". As previously commented, the MRO NSRF does not agree with the 90 calendar day timeframe and believes it should be 120 days similar to PRC-004-6. Further, the SDT commented in the draft two responses the reason for maintaining the 90 calendar day timeframe was "to ensure diligence", the MRO NSRF does not feel that this is an acceptable justification for maintaining a 90 calendar day timeframe.

PRC-030-1, Requirement R2, Draft 4. The MRO NSRF does not agree with allowing the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA) to be able to request an analysis of any a change in “the inverter-based resource(s) Real Power output”; the criteria for this analysis shall be the same criteria as outlined in Requirement R1.

- PRC-030-1, Requirement R3, Draft 4: The MRO NSRF would like to reiterate that being required to provide either a ‘Corrective Action Plan or justification of why corrective actions will not be applied to the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA)’ is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6, is administrative in nature without any reliability benefit and not cost effective. The MRO NSRF suggests the following language:

o “…and upon request provide it to the applicable associated Reliability Coordinator, Balancing Authority, and Transmission Operator:”

- PRC-030-1, Requirement R4.3, Draft 4. The MRO NSRF would like to reiterate that the proposed Requirement R4.3 is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6,

is administrative in nature without any reliability benefit and not cost-effective. In addition, the MRO NSRF does not understand why the Balancing Authority, and Transmission Operator are not included in the requirement language. The MRO NSRF suggests making requirement R4.3 contingent on requests made under Requirement R3. Essentially, a responsible entity only needs to provide external updates of the corrective actions plans to the requesting entity if those corrective actions plans were requested under Requirement R3.

Based on the aforementioned comments the MRO NSRF suggests combining Requirements R1 & R2 as follows:

R1. Each applicable Generator Owner, within 120 calendar days of 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 4 second period, or following a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the

Inverter-Based Resource(s) Real Power output that are at least 20 MW and at least 10% of the plant's gross nameplate rating, occurring within a 4 second period, shall, 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 IBR generator; or

· Real Power reduction due solely to BES interrupting device operations being analyzed under NERC Reliability Standard PRC-004.

1.1. Analyze its IBR facility performance during the event, including:

1.1.1. Determine the root cause(s) of change(s) in Real Power output;

1.1.2. Document the facility’s Ride-through performance including Reactive Power response during the event;

1.1.3. Assess any performance issues identified and if corrective actions are needed; and

1.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities. 1.2. Upon request, provide the analysis results to the requesting associated Reliability Coordinator, Balancing Authority, or Transmission Operator.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to the MRO NSRF.	
Michael Goggin - Grid Strategies LLC - 5	
Answer	Yes
Document Name	
Comment	
We are highly concerned that, relative to the first draft, the current draft of the standard reduces the threshold for output change events that must be reviewed to determine if they need to be analyzed. The revised standard sets the threshold at a change in output that is greater than 10% of the plant's nameplate rating (and greater than 20 MW) within 4 seconds, relative to the threshold of 20% within 2 seconds in the initial draft. This change only adds to our concerns about the generator owner's burden of manually reviewing each output change to exclude events caused by normal fluctuations in plant output due to weather, dispatch, and other factors. No mechanism exists for generator owners to automatically exclude those permissible changes from consideration. Wind and solar plants have a limited number of meteorological towers and pyranometers for measuring the available wind and solar resource, respectively, which makes it difficult in many cases to precisely determine whether changes in output across a plant were caused by resource availability. The new lower threshold will pick up many more such events, as changes of 10% output within 4 seconds can routinely occur at solar and wind plants. As we explained in our previous comments, the passage of clouds over medium-sized solar plants can cause changes in	

output that are larger than this threshold.[1] As a result, in some cases a large share of the events a generator owner is required to review will be these normal changes in output, diverting their time and resources away from addressing real reliability concerns.

The drafting team's response to our comments in the first round of balloting only reinforces our concern about the burden imposed on the generator owner: "GOs would not know if it was unexpected behavior of generator settings and controls until the analysis is performed. The exceptions that have been moved from the footnote to the Standard Language allow for GOs to dismiss events due to cloud cover, change in wind speed. etc. Outage/Fault codes would be reviewed during the analysis process. It will be up to GOs to develop a process to identify events that that do not fit into the listed exclusions and require further analysis." It is highly burdensome for a generator owner to pull turbine- or inverter-level fault codes and plant-level fault codes for each event with a more than 10% change in output. Moreover, the drafting team cannot ignore the excessive and unworkable burden imposed on generator owners by simply dismissing that with "It will be up to GOs to develop a process to identify events that that do not fit into the listed exclusions and require further analysis."

As explained in our answer to question 2 below, the best solution to these concerns may be to remove most if not all of R1, and instead rely on analysis requests initiated by the Reliability Coordinator, Balancing Authority, or Transmission Operator following a disturbance event that causes a drop in generator output per R2.

Second, we are concerned that generator owners will be required to conduct a full analysis of all events in which an IBR plant reduces real power output to prioritize reactive power output, as is desirable and expected during voltage disturbances. The standard should be revised to include a mechanism to automatically screen out disturbance events in which the IBR generator briefly reduced real power output because it entered reactive power priority mode.

During a voltage disturbance on the bulk power system, the most helpful response is typically for generators to shift some of their power output from providing real power to prioritizing reactive power to help prevent voltage collapse.[2] As experts at the Energy Systems Integration Group (ESIG) explain, summarizing the conclusions of a recent workshop on generator interconnection, "If too much active power is injected into a point of interconnection with already depressed voltage, it may further collapse the voltage, causing more cascading outages and compromising the reliability of the grid. Rather than keeping the active power of an IBR at a pre-disturbance level, it is more beneficial to reduce active power, depending on severity of voltage drop thus preventing further voltage collapse — while reactive power is prioritized and increased to support grid and terminal voltage."[3]

Not only does a requirement to maintain active power production instead of prioritizing reactive power production during a voltage disturbance risk exacerbating voltage collapse, but it is also infeasible in many cases. If the voltage is low during and following a disturbance, even if an IBR plant continues to inject its full pre-disturbance level of active current, it cannot maintain the level of active power it was delivering because voltage is now lower and active power is the product of voltage and current. Moreover, to increase reactive power injection, a generator must typically shift its output away from active power injection (power is comprised of active and reactive components). Both synchronous and asynchronous generators have a finite ability to produce power, so they must reduce real power (P) production to increase reactive power (Q) along the P-Q generator capability curve.[4] In most cases, it is infeasible for any type of generator to maintain active power production while also increasing reactive power output during a disturbance.

Solutions

To address the concerns expressed in our answer to question 1 above regarding the burden on generators of screening out changes in output that are not caused by disturbances, the best solution may be to remove most if not all of R1, and instead rely on analysis requests initiated by the Reliability Coordinator, Balancing Authority, or Transmission Operator following a disturbance event per R2. This would remove the inefficient “needle in the haystack” burden on generators under R1 to screen every output change event to find the small subset that are due to disturbances, and instead only focus resources on reviewing significant disturbance events that coincided with a change in generator output. Because many generators do not have synchrophasors or other equipment required to determine when significant grid disturbances have occurred, it makes more sense for the analysis to be initiated by a request from the RC, BA, or TO. Relatedly, we reiterate our request from the first comment period to add a requirement to R2 that the RC, BA, or TO must file its request within 15 days of the disturbance event. This will ensure that the GO has at least five days to pull data before it is overwritten, given that the data retention period in the current draft of PRC-028 R7 is 20 days.

As explained above, the standard should also be revised to include a mechanism to exclude analysis of disturbance events in which the IBR generator briefly reduced real power output because it entered reactive power priority mode.

Finally, the requirement on the generator owner in 2.1.4 to “Determine the applicability of the root cause(s) to the Generator Owner’s other Inverter-Based Resource facilities” appears to be unreasonable if not unworkable. A company that owns multiple IBR plants typically uses different equipment and settings across its plants, and some may be wind plants while others are solar plants, so there is no reason to assume its other plants have the same susceptibility simply because they have the same owner. At minimum, the requirement should be clarified to specify whether projects owned by the same parent company but that are incorporated as separate LLCs must be assessed as part of compliance with 2.1.4., and other such details.

{C}[1]{C} https://www.sciencedirect.com/science/article/abs/pii/S0306261917300144

{C}[2] https://www.esig.energy/download/interconnection-requirements-need-for-harmonization-jason-macdowell/?wpdmdl=9267&refresh=62f587eab15591660258282, at 6

{C}[3]{C} https://www.esig.energy/wp-content/uploads/2022/10/Joint-Generator-Workshop-Summary-1.pdf, at 29

{C}[4] See Figure 4 for an example of a synchronous generator's P-Q curve and Figure 5 for a non-synchronous generator's P-Q curve: https://link.springer.com/article/10.1007/s40565-019-0535-4

Likes 0	
Dislikes 0	

Response

Thank you for the comments and concern. The DT performed an assessment on how frequently the thresholds could be met and included this information in the Technical Rationale. The DT agrees that some data automation will be helpful for screening events. The DT recognizes some expected, proper performance could meet the Requirement R1 thresholds and require further investigation. Capturing some level of false positives is a consequence of most simple screening methods. The DT aimed to balance accuracy, and mitigation of risks in developing the criteria to help further reliability.

Colin Chilcoat - Invenergy LLC - 6

Answer	Yes
Document Name	

Comment

As currently drafted, Invenergy believes PRC-030-1 imposes a significant resource burden on GOs without commensurate benefit to reliability. GOs will need to dedicate significant resources to identify, analyze, and validate events that may pose no reliability concern. Invenergy understands that regional entities may not have the ability to identify single plant performance issues, but they would be able to identify events that have a system-level impact, at which point the GO could be instructed to provide greater analysis of its performance during that specific time period.

Likes 0	

Dislikes 0	
Response	
The purpose of the SAR for Project 2023-02 is to have GOs self-identify events and investigate performance, the DT felt this is the best course forward to ensure reliability. The SAR notes, "It is important that the GO is accountable for analyzing these events, has necessary monitoring equipment installed, and cooperates with the BA/RC by providing operational data and analytical results. The past few NERC disturbance reports have highlighted limited awareness and understanding by facility owners that abnormal performance has even occurred, and therefore identification of possible performance issues should be initiated by either the IBR facility owner/operator (i.e., the GO/GOP) or by the transmission entities with a wide-area view (i.e., the TOP, RC, or BA). However, the onus of analysis and development of mitigating actions should be on the asset owner to eliminate the possible risk of repeated abnormal performance issues."	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	
PRC-030-1 imposes a significant resource burden on GOs without commensurate benefit to reliability. GOs will need to dedicate significant resources to identify, analyze, and validate events that may pose no reliability concern. Invenergy understands that regional entities may	

not have the ability to identify single plant performance issues, but they would be able to identify events that have a system-level impact, at which point the GO could be instructed to provide greater analysis of its performance during that specific time period.	
Likes 0	
Dislikes 0	
Response	
The purpose of the SAR for Project 2023-02 is to have GOs self-identify events and investigate performance, the DT felt this is the best course forward to ensure reliability. The SAR notes, "It is important that the GO is accountable for analyzing these events, has necessary monitoring equipment installed, and cooperates with the BA/RC by providing operational data and analytical results. The past few NERC disturbance reports have highlighted limited awareness and understanding by facility owners that abnormal performance has even occurred, and therefore identification of possible performance issues should be initiated by either the IBR facility owner/operator (i.e., the GO/GOP) or by the transmission entities with a wide-area view (i.e., the TOP, RC, or BA). However, the onus of analysis and development of mitigating actions should be on the asset owner to eliminate the possible risk of repeated abnormal performance issues."	
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	

It is the opinion of ACES that PRC-030-1 Requirement R1 should be more aligned with PRC-004-6 Requirement R1. In short, we believe that requiring a documented process to identify applicable events at an IBR, as is currently required by PRC-030-1 R1, increases the compliance burden for the GO with no appreciable decrease in the risk to the BPS. Therefore, we recommend striking the phrase "implement a documented process to" from PRC-030-1 Requirement R1. The revised version of R1 would thus read as follows:

R1. Each applicable Generator Owner shall 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 4 second period. 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 IBR generator; or
- Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.

Secondly, ACES does not agree with the removal of the word “identifying” from Requirement R2. It is the opinion of ACES that removing this word places an undue burden on the GO to perform the analysis within an unnecessarily compressed timeline. While it is still our opinion that a timeline of 120 days is more appropriate as it is more consistent with PRC-004-6; we do not see it as an insurmountable hurdle to require a 90 calendar-day timeline so long as it begins when the GO identifies the event. Thus, we recommend modifying R2 as follows:

R2. Each applicable Generator Owner shall perform the activities identified in each subpart of this Requirement, within 90 calendar days, of either:

- identifying a Real Power change event pursuant to Requirement R1 or,
- receiving a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator wherein the requesting entity identified an event meeting the thresholds established in Requirement R1

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in Real Power output;

2.1.2. Document the facility’s Ride-through performance including Reactive Power response during the event;

2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the applicability of the root cause(s) to the Generator Owner’s other Inverter-Based Resource facilities.

2.2. Upon request, provide the analysis results to the requesting associated Reliability Coordinator, Balancing Authority, or Transmission Operator.

Furthermore, it is the opinion of ACES that the GO should not be required to submit a CAP to the RC, BA, nor TOP. This is not in line with the requirements identified in PRC-004-6 Requirement R6 nor does it add any appreciable reduction in risk while at the same time increasing the compliance burden for the GO and likely the RC, BA, and/or TOP. In other words, why should the GO submit its CAP to these entities if they are not required to perform any action(s) upon receipt (or even acknowledge receipt)? In short, if the RC, BA, or TOP

desires an opportunity to review the CAP(s) developed by the GO, there is already a mechanism in place for this via the documented data specification(s). Lastly, requirements R3 and R4 of the proposed PRC-030-1 do not align with one another. For example, as written, R3 requires a CAP be provided to the RC, BA, and TOP whereas R4 Part 4.3 only requires that the RC be notified. We recommend modifying these sections so that they are inline with one another. In other words, either require the GO to notify the RC, BA, and TOP in R4 Part 4.3 or remove the BA and TOP from Requirement R3.	
Likes 0	
Dislikes 0	
Response	
The DT reviewed the suggestion however kept the documented process because it is an important element to ensure a process is in place that could adequately capture events. The documented process requirement can be found in other Reliability Standards such as CIP-003, CIP-004, CIP-005, and PRC-012. The DT reviewed the suggestion and considered increasing the time however is holding to 90 days to ensure analysis and correcting unexpected performance is a focus for the GO. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes. The DT removed the "identifying" qualifier in Requirement R2 prior to posting Draft 4 for additional ballot and tied the timing of R2 to the event date. This change was made because, as originally written, there was an open-ended timing problem for the GO to identify the event. Without tying the GO's identification response to the event date, there is a risk of missing events entirely due to lack of information or persistence. The RC, BA and TOP are ultimately responsible for the operation and security of the BES and BPS. As such they are accountable to know and understand the limitations and issues in the electric system, requiring knowledge of respective Corrective Action Plans.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
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	
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
ITC has no comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	

No comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	

2. Provide any additional comments for the Drafting Team to consider, if desired.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
ATC had not initially joined the ballot pool for this standard as it was not directly applicable to TO/TOP, however, we would like to express our support of the standard as written and thank the team for their effort.	
Likes 0	
Dislikes 0	

Response	
Thank you for the support.	
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 the response.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	
Document Name	
Comment	
NRG is in alignment with NAGF's comments	
Likes 0	
Dislikes 0	
Response	
Please see response to NAGF’s comment.	
Usama Tahir - Seminole Electric Cooperative, Inc. - 3	
Answer	

Document Name	
Comment	

1. If a device can impact a plants gross nameplate rating by 10% or 20 megawatts respectively, does that Cyber Asset now become CIP applicable? I.e., what impact to CIP will this have if the measure of detriment is 20 MW or 10% of a total unit? Can the Standard Drafting Team add color to this question?
2. Take for instance a site that has both PV and BESS. The PV has a gross nameplate of 74.5 MW. The BESS has a gross nameplate of 30 MW. However, the site is synthetically limited to 74.5 MW, i.e., the output cannot exceed 74.5 MW. Would the Generator Owner still need to use the gross nameplate rating of the combined generators or can the 20 MW/10% value be calculated off of any synthetically limited value?
3. GO should have a time period of 120 days in R2 after identification of R1 events and 120 days to complete R3, to be consistent with PRC-004 Requirements. This will give entities a chance to determine which Standard to apply to an event.]
4. R4.3 reporting requirements should be consistent with PRC-004 R6. PRC-004-6 R6 does not require notification every time a CAP changes. The Standard Drafting team should mirror this language or add context into the technical guidance that describes why reporting should differ.
5. The Standard Drafting team should identify which elements to evaluate as requiring a CAP (i.e. elements that are directly responsible for the ride-through capabilities of an IBR).

Likes 0	
Dislikes 0	

Response

1. CIP applicability is outside the scope of this standard.
2. Please refer to the facility definition in the application section of the standard. PRC-030's Requirement R1 language also looks at the "plant's gross nameplate language."

3. The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes.
4. Thank you for the comment.
5. Determination of elements requiring a CAP should be left to the applicable entities responsible for root cause analysis.

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 for the support, see response to NPCC Standards Committee's comments.	
Bret Galbraith - Seminole Electric Cooperative, Inc. - 6	
Answer	
Document Name	
Comment	

1. If a device can impact a plants gross nameplate rating by 10% or 20 megawatts respectively, does that Cyber Asset now become CIP applicable? I.e., what impact to CIP will this have if the measure of detriment is 20 MW or 10% of a total unit? Can the Standard Drafting Team add color to this question?
2. Take for instance a site that has both PV and BESS. The PV has a gross nameplate of 74.5 MW. The BESS has a gross nameplate of 30 MW. However, the site is synthetically limited to 74.5 MW, i.e., the output cannot exceed 74.5 MW. Would Seminole still need to use the gross nameplate rating of the combined generators or can the 20 MW/10% value be calculated off of any synthetically limited value?
3. GO should have a time period of 120 days in R2 after identification of R1 events and 120 days to complete R3, to be consistent with PRC-004 Requirements. This will give entities a chance to determine which Standard to apply to an event.]
4. R4.3 reporting requirements should be consistent with PRC-004 R6. PRC-004-6 R6 does not require notification every time a CAP changes. The Standard Drafting team should mirror this language or add context into the technical guidance that describes why reporting should differ.
5. The Standard Drafting team should identify which elements to evaluate as requiring a CAP (i.e. elements that are directly responsible for the ride-through capabilities of an IBR).

Likes 0	
Dislikes 0	

Response

1. CIP applicability is outside the scope of this standard.
2. Please refer to the facility definition in the applicability section of the standard. PRC-030's Requirement R1 language also looks at the "plant's gross nameplate language."
3. The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes.
4. Thank you for the comment.
5. Determination of elements requiring a CAP should be left to the applicable entities responsible for root cause analysis.

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 the support.

Colin Chilcoat - Invenergy LLC - 6

Answer	
Document Name	

Comment

Thank you for the opportunity to provide comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

ERCOT supports modifying the criteria in Requirement R1 to 20 MW ***OR*** 10% instead of 20 MW **AND** 10%. Inverters/wind turbines/etc. will typically be 1-3 MW in size (with newer technologies approaching 4-5 MW). 10% of a 500 MW facility would be 50 MW and 10% of a 1,000 MW facility would be 100 MW (both of which are present and growing in new interconnection queues), which are excessive thresholds. One approach to address this issue would be to set both a floor and a ceiling by establishing a threshold of 20 MW **AND** 10% for IBRs with a nameplate capacity of less than 200 MW nameplate and to set a threshold of 20 MW **OR** 10% for IBRs with a nameplate capacity greater than or equal to 200 MW.

ERCOT recommends modifying the third bullet of R1 to be “• A Transmission or collection system loss that***, through normal clearing***, disconnects the IBR generator;” which would better align with the language used in other locations in the standards that describe normal clearing of faults.

ERCOT recommends that the reporting requirement in Requirement R2 be expanded to include a report to the RC, BA, and TO within three business days of the identification of an event. Although a GO/GOP may not have had adequate time to fully assess and analyze the incident at that point, the degree of the unexpected operation may pose significant risk that an operator may need to be aware of for

situational awareness. The operator may have seen an impact on the system that could not be explained without this information. A follow-up report when the incident is fully assessed would still be communicated to the operator(s) for any longer-term considerations. Finally, in light of FERC's directives in its *Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification*, and in light of modifications made by the PRC-029 SDT, ERCOT believes that NERC should be a part of the review process for any instances in which a GO does not implement a CAP as provided in the 2nd bullet of Requirement R3. For informational purposes, the pertinent language from FERC's Order is provided below (emphasis added). 33. Under Reliability Standard EOP-012-1, a generator owner could explain in a declaration any "technical, commercial, or operational constraints" that preclude its ability to either implement freeze protection measures or implement corrective action plans. However, Reliability Standard EOP-012-1 ***does not define "technical, commercial, or operational constraints," leaving those terms open to interpretation by each generator owner***. In the February 2023 Order, the Commission approved Reliability Standard EOP-012-1 but ***expressed concern with the uncertainties, ambiguities, and vagueness of the Standard's descriptions of constraints, noting that, without criteria to guide the generator owners or guardrails on what constitutes a legitimate constraint, generator owners may avoid the purpose of the Standard altogether or have declarations without auditable elements***. Thus, the ***Commission directed NERC to address the ambiguity of generator owner-defined declarations by including auditable criteria to ensure that declarations cannot be used to avoid mandatory compliance with the Reliability Standard or obligations in a corrective action plan***.	
Likes 0	
Dislikes 0	
Response	
The DT determined that the threshold as written would eliminate smaller events and appropriately balance risks while ensuring reliability. The RC, BA or TOP can request analysis of events outside R1 criteria when the GO is self-identifying events in Requirement R1. In Requirement R2 Part 2.2 this gives the Reliability Entity the ability to request a GO perform analysis and prove the Reliability Entities the results.	

Under Requirement R2, the GO has 90 days to perform the analysis of the event. The DT felt that 90 days provided an appropriate amount of time for a GO to analyze the event to promote reliability. The DT determined that at least 20 MW or at least 10% would eliminate smaller events and appropriately balance risks while ensuring reliability. The DT was limited to the parameters of SAR in regard to the EOP-012 comment.

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 Standard Drafting Team's actions to change the Section 4, Applicability language to match that in the proposed PRC-028-1 and PRC-030-1 reliability standards. Although time is short to make further changes, the following improvements should be considered by this Standard Drafting Team or a future Team to enhance PRC-030-1. 1) PRC-030-1, Requirement R1, Draft 4 still contains an overlap with NERC Reliability Standard PRC-004-6, Requirement R1. The exclusionary bullet four assumes that a Misoperation has occurred and does not leave room for correct operations of protection systems. This would create an unnecessary burden on registered entities to create compliance documentation for both PRC-004 and PRC-030 for the same event caused by the correct operation of a protection system. We agree with the recommendation provided by the MRO NSRF to revise the bullet four language to the following and remove the overlap: "Real Power reduction due solely to BES interrupting device operations being analyzed under NERC Reliability Standard PRC-004." 2) PRC-030-1, Requirement R2, Draft 4, "90 calendar day". SMUD does not agree with the 90 calendar day timeframe and believes it should be 120 days similar to PRC-004-6.	
Likes 0	

Dislikes 0	
Response	
1. Thank you for the comment. The DT exempted Protection System Misoperations from the Requirement R1 determination however correct operations of Protection Systems need to be analyzed to verify Ride-through performance requirements. 2. The DT reviewed the suggestion however the DT considered increasing the time and is holding 90 days to ensure analysis and correcting unexpected performance is a focus for the GO. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes.	
Patricia Ireland - DTE Energy - 4, Group Name DTE Energy	
Answer	
Document Name	
Comment	
The PRC-030 standard language (Applicability Section 4.2.2) needs to align to Project 2020-06 for defining the term that will represent Category 2 IBRs Similarly, the PRC-030 Implementation plan (footnote 8 on page 3 and the term definition for "applicable non-BES IBRs" used on Page 4) needs to align to Project 2020-06 definition of the Category 2 BES	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. There are no category 2 IBRs in 2020-06 IBR Definition. The facilities section aligns with the change in NERC Rules of Procedures (ROP) and those that leverage the definition for IBR need to specify which IBR.	
Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	
Document Name	

Comment	
Kindly suggest greater consideration of the standard drafting team to take in consideration therecommendations made by OEM and GO/GOP of existing IBRs on capabilities vs reliabiliaty improvement vs cost, from previous and current commenting.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team developed the standard in alignment with the SAR while balancing the need between ensuring continued reliability of the grid and due consideration of industry stakeholder inputs.	
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	
SRP supports the standard but would like to see the 90 day portion of R2 reduced to 7 days. In order to ensure impacts to the BES are minimized, it seems important to define root causes to determine if an IBR can be safely returned to service or if mitigations need to be prepared if returned to service, or if the IBR needs to be kept on forced outage until mitigated. As we become more and more dependent on this type of resource for load serving and regulating needs this level of urgency is warranted in our opinion.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team developed the standard and timing requirements based on reliability needs and industry stakeholder inputs.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	

Document Name	
Comment	

R1 requirements
The technical rationale states that criteria for triggering analysis were chosen with the intention of screening out “small active power changes” while being low enough to detects events that present a reliability risk. The DT points to 3 studies performed at solar and wind facilities in Texas where wind speed and solar irradiance changes did not result in greater than a 20mw or 10% nameplate rating Real Power output ? in a 4 second window. These studies ranged from 1 month to 1 year, and 160MW-500MW nameplate ratings. Many factors can affect both the Real Power output, as well as the Power rate of change for IBR’s, particularly solar, where temperature, latitude, elevation, humidity, asset age, and geographical features, can all impact the effective output and how fast it may change based on disturbances to its energy source. These studies may provide insufficient data to draw wide conclusions about what changes in Real Power output due are likely for a given ? across the entire North American footprint, as the data is limited to a relatively narrow geographical location, number of facilities, and timeframe. Region-specific studies with more robust data would inspire confidence these changes do not present an undue burden in the way of nuisance event analysis.
R2 & R3 requirements
The time periods in R2 and R3 should be increased to 120 calendar days to allow time to determine the root cause and develop a Corrective Action Plan, especially if OEM support is required.
The stated rationale for the discrepancy between the PRC-004 analysis requirement of 120 days and the proposed PRC-030 requirement of 90 days is that: “The PRC-004 timeframe accounts for extreme weather events such as hurricanes that may affect a very large number of Protection Systems for a given responsible entity”. Additionally it is stated that: “The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed”
The same extreme weather events that cause numerous PS operations can, and may even likely occur at the same time that unexpected output events occur for IBRs. Typically, it will be the same teams that analyze both of these types of events.
Furthermore, it is unclear on what basis the SDT has determined that 90 days allows sufficient time to provide thorough IBR response analysis as no evidence is presented. IBR proprietary control systems remain a major obstacle to analysis, and will necessitate communication with external vendors which are not bound by the compliance timeframe requirements of the PRC.
The same issues regarding control systems and external vendors will also exist for developing CAPs.

Likes 0	

Dislikes 0	
Response	
The DT finds the thresholds to be reasonable based on the data, expertise and studies that are available and considering system risk. Note that the TR does include some studies outside ERCOT including NREL studies. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes. The DT members feel that 90 days ensures reliability and extending that would not ensure reliability. In the case where it is not possible to obtain information from the OEM in 90 days, the GO could document that information was requested from the OEM and document the best attempt at a root cause based on what they are able to determine from the information available. The DT believes it is important to include a time requirement. The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The CAP should be written in such a manner so as to follow up on data collection that is still in process as well as challenges regarding engagement with OEMs and external vendors.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
WEC Energy Group supports the comments of the MRO NSRF and the NAGF.	
Likes 0	
Dislikes 0	
Response	
Please see responses to MRO NSF and the NAGF.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	

Document Name	
Comment	

The NAGF has identified several concerns regarding the proposed revisions:

1. *Substantive change in Requirement R2: The removal of the word "identifying" in relation to the 90-day timeline for real power change events was seen as a significant change that could shorten the response time for entities. Therefore, the NAGF recommends removing the proposed wording change and leaving the language as is from PRC-030 Draft #3 that was approved by industry.*
2. *Inconsistency between R3 and R4: R3 requires the Corrective Action Plan (CAP) to be provided to the RC, BA, and TOP, while R4 only mentions the RC. This inconsistency was noted as potentially problematic.*
3. *VSL terminology: The continued use of the term "susceptibility" in the Violation Severity Levels (VSLs) was highlighted, despite its removal in previous versions of the standard.*
4. *Implementation plan changes: The removal of a paragraph linking PRC-30 to PRC-29 in the implementation plan was seen as a significant change that could impact the sequential implementation of these standards.*
5. *Lack of clarity on actions required: There was uncertainty about what actions the RC, BA, and TOP need to take upon receiving the CAP.*

Likes 0	
Dislikes 0	

Response

1. The DT removed the “identifying” qualifier in Requirement R2 and tied the timing of R2 to the event date because as originally written, there was an open-ended timing problem for the GO to identify the event. Without tying the GO’s identification response to the event date, there is a risk of missing events entirely due to lack of information or persistence.

2. The RC, BA and TOP are ultimately responsible for the operation and security of the BES and BPS. As such they are accountable to know and understand the limitations and issues in the electric system, requiring knowledge of respective Corrective Action Plans. With Requirement R4, the DT felt the CAP only had to go to the RC for the purposes of updating the timelines. This was to relieve administrative burden on the GO’s when submitting the CAP.

3. Thank you for the recommendation, the team will make this conforming non substantive change removing the word susceptibility for the VSL language and replacing it with applicability along with updating the number to reflect the correct sub-bullet of Requirement R2 2.1.4.

4. The Implementation Plan for PRC-030 includes as the pre-requisite PRC-029 in the latest Implementation Plan. The Implementation Plan from the last draft included language "Where approval by an applicable governmental authority is required, Reliability Standard PRC-030-1 shall become effective on the 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 PRC029-1, or as otherwise provided for by the applicable governmental authority." under the effective date section in response to the aforementioned paragraph that was removed from the previous version of the Implementation Plan.

5. This concern is outside of the scope of this DT's SAR coverage for this project.

Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	

Constellation thinks "Nameplate rating" needs to be clarified as there are many ways to define that especially for solar and storage plant. Recommend adding "at the Point of Interconnection as defined in the interconnection agreement" in R1. Further, although the analysis completion was changed from 45 days to 90 days in R1. Timeframe needs to be adjusted to 120 days to match PRC-004 .

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

1. Nameplate rating was used as the basis of the change (power or amperes) because it is the common reference in NERC and other industry standards. Nameplate was chosen because every generator has a nameplate rating that can be referenced. Nameplate rating is also included as the reference point as it is included in the BES definition.
2. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes. The DT members feel that 90 days noted in R2 ensures reliability and extending that would not ensure reliability.

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

Duke Energy agrees with and suggest implementation of NAGF comments #1, #3 and #4 identified below:

#1: Substantive change in Requirement R2: The removal of the word "identifying" in relation to the 90-day timeline for real power change events was seen as a significant change that could shorten the response time for entities. Therefore, the NAGF recommends removing the proposed wording change and leaving the language as is from PRC-030 Draft #3 that was approved by industry.

#3: VSL terminology: The continued use of the term "susceptibility" in the Violation Severity Levels (VSLs) was highlighted, despite its removal in previous versions of the standard.

#4: Implementation plan changes: The removal of a paragraph linking PRC-30 to PRC-29 in the implementation plan was seen as a significant change that could impact the sequential implementation of these standards.

Additionally, Duke Energy notes that PRC-030 is dependent on data from PRC-028.

Likes 0	
Dislikes 0	

Response	
Thank you for your comments. Please see responses to #1, #3, and #4 of NAGF's comment. The DT made the decision in earlier drafts to not include PRC-028 as it is not a prerequisite needed for PRC-030. The way the PRC-030 standard is drafted it does not need data dependent on the PRC-028.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation agrees with and supports NAGF comments. In addition, Black Hills Corporation is concerned with the standard not defining a time frame for RC, BA, or TO notify GO of a disturbance. Black Hills Corporation's current practice is to maintain a rolling years' worth of data, it is unclear if this would be sufficient for compliance with the standard.	
Likes 0	
Dislikes 0	
Response	
Please see responses to NAGF comments. Thank you for your comments the DT felt it was not necessary to add a timeline to the reliability entities to ensure reliability, the DT discussed with BA, RC, TOP DT members how this process operates. With the current guidance and best practices by the BA, RC, and TOPs the DT felt no timeline was needed.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	

Comment	
1) Shouldn't another bullet be added in the exclusion list in R1? · Real Power reduction due solely to a RAS (Remedial Action Scheme) Misoperations being analyzed and corrected under PRC-012 Reliability Standard	
Likes 0	
Dislikes 0	
Response	
Thank you for the response and comment, the team based on previous comments received in previous drafts felt these exclusions were necessary to ensure reliability. This would be remedied as it is part of a technical justification in Requirement R2 in the current PRC-030.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	
Comment	
Substantive change in R2 - Standard (1st screenshot) has been updated to remove "identifying" from R2. By making this change the 90 day timeline is effectively shortened during which entities have to analyze the event, because entities will not be able to "identify" events in real time. Implementation plan changes: The removal of a paragraph linking PRC-30 to PRC-29 in the implementation plan was seen as a significant change that could impact the sequential implementation of these standards. Lack of clarity on actions required: There was uncertainty about what actions the RC, BA, and TOP need to take upon receiving the CAP.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. Please see responses to NAGF comments.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	
Comment	
The MRO NSRF thanks the SDT for consideration of these and previous comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
If BAs, RCs, and TOPs needed this data then they have had years to request it via their interconnection agreements and market rules.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	

Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
Requirement R3 mandates that all CAPs or justifications from “performance issues and corrective actions [that] were identified in Requirement R2 Part 2.1.3” be provided “to the applicable RC, BA, and TOp”. However, not all issues and actions from Requirement R2	

were identified or communicated to the GO from the RC, BA, or TOp. As such, only the ones coming from the RC, BA, or TOp should have to be provided back to them and then, only to the one(s) that provided it to the GO, not necessarily to all three. Similar comment to Requirement R4.3 - only the CAP actions resulting from a notification from the RC should have to be reported back to the RC. Also, what about the CAP actions resulting from a BA or TOp notification - shouldn't they be communicated back to them?	
Likes 0	
Dislikes 0	
Response	
The RC, BA and TOP are ultimately responsible for the operation and security of the BES and BPS. As such they are accountable to know and understanding the limitations and issues in the electric system, requiring knowledge of respective Corrective Action Plans. With Requirement R4, the DT felt the CAP only had to go to the RC for the purposes of updating the timelines. This was to relieve administrative burden on the GO's when submitting the CAP.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP would like to thank the SDT for revising R2 to make it clear that the expectations are within 90 days of the event itself, and for replacing the word "applicable" with "associated" throughout the standard in regards to the Functional Entities. On the previous ballot period, the SDT responded to AEP by stating "In the case where a root cause cannot be identified, this would conclude the analysis portion of Requirement R2. However, ***mitigating actions should be implemented*** so that a root cause can be determined for subsequent events, such as correcting inverter logs and insufficient data capture." While AEP agrees in principle that doing so would be a reasonable approach, we do not believe the standard obligations themselves clearly convey such expectations, as this language is not included in the standard nor insight provided within the Technical Rationale. This language needs to be explicitly included in the standard, so that it is fully understood and consistently executed by Functional Entities. In addition, the standard could be further improved by revising it to accommodate for situations when a cause is found, but where an entity is unable to fully mitigate it.	
Likes 0	

Dislikes 0	
Response	
The DT believes that the requirements drafted provide sufficient clarity. However, in response, the DT has provided additional clarifying language in the Technical Rationale.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
FirstEnergy continues to request clarification on the determination of what would be a failure vs. weather as related to Requirement 1. FirstEnergy would request an expansion of the threshold criteria that would fall under PRC-030-1, understanding the scan rate is able to detect these changes, these minor occurrences and investigations potentially take the primary focus away from the protection of the BES.	
Likes 0	
Dislikes 0	
Response	
The DT does not expect there to be many weather related events such as change of wind speed or change in irradiance that would cause the facility to meet the threshold requirements related to Requirement R1. Please refer to the analysis provided in the TR document. Please refer to the TR document in response to your comment.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	

Comment	
WECC voted affirmative but offers the following for consideration. Standard comments- Consider spelling out Inverter-Based Resource in the third bullet of Requirement 1 that currently is just "IBR" to be consistent with other Requirements. Consider capitalizing "inverter-based resource" in Requirement R2 Severe VSL. Requirement R3 Lower, Moderate, and High VSLs need to reflect "calendar days" to match the Requirement language (and the Severe VSL language) Implementation Plan comments-The title of Standard PRC-029 is not correct (should be "PRC-029-1 Frequency and Voltage Ride-through Requirements for Inverter-Based Resources"). In the "Background" section first sentence there is a need to update "inverter-based resources (IBR)" and replace the added "Inverter-Based Resources (IBR)" with simply "IBRs". Determine if a hyphen is needed or not for "BPS-connected" as both are used. Need to lower case the "s" in "IBRS" in the last sentence of "General Considerations". Footnote 8 needs edited to remove the first "as" between "such" and "IBRs". Need to lower case the "s" in "IBRS" in the sentence under "Bulk-Electric System IBRs" header. Although allowed, consider consistency in use of "Bulk Electric System" or "Bulk-Electric System" especially when sitting next to each other in document. Suggest simply use "BES IBRs" as the header and the first part of sentence under the "Bulk-Electric System IBRs" header. Consider removal of "Applicable" for the "Applicable Non-BES IBRs" header as it is unnecessary. The definition provides what a Non-BES IBR may be and a Standard would determine the applicability. If the DT thinks "applicable" is necessary, why is it not a modifier for "Bulk-Electric System IBRs" section? It is not clear what the last sentence under the header "Applicable Non-BES IBRs" provides. Note the first part of the sentence (if retained as is) needs corrected to "Applicable Non-BES Inverter-Based Resources." It should be noted within the Implementation Plan and/or Technical Rationale that the Non-BES IBR definition reflects the ROP definition for Category 2 (and does not capitalize "inverter-based resource".) Now, with the "Applicable" modifier, the sentence reads as if there **are more** Non-BES Inverter-Based Resources that are included in the Phased-in Compliance considerations. Suggest removal of "Applicable" and the last sentence. If not, then the DT needs to explain what other "Applicable Non-BES IBRs" are outside of the defined Non-BES IBRs. There is a SAR that is considering "IBR-DER", "Sub-BES IBR", and "Non-Material IBR" definitions but that is in early stages of consensus building.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The DT has considered and made all non-substantive changes in response to your comments wherever is appropriate. The DT notes the applicability is consistent with what is defined in footnote 8 in the Implementation Plan.	

Brian Lindsey - Entergy - 1	
Answer	
Document Name	
Comment	

Implementation Plan:

This is not a phased in implementation plan. Also, Entergy is concerned that the implementation of PRC-030 is dependent on the implementation of PRC-029 which has not been approved yet.

The implementation plan should be 365 days instead of 90 days to allow for any control changes that might be required. A process may need to be added to allow extensions of implementation based on potential supply chain issues.

Requirements:

R2. Data quality concern in an event happening in 4 seconds and being able to complete the analysis.

Concerns with having to provide the information to multiple entities.

R3 & R4. The reporting requirement should be synchronized with R3 and R4. Corrective plans should be intended for internal use only and not necessary to be reported out to other entities. What is the need and useability of that information to those entities?

The action to create the Corrective Action Plan should 90 days instead of 60 days. Recommend adding language in R3 that states that if all actions are completed during the analysis phase to correct the issue there will be no need for a CAP.

Likes 0	

Dislikes 0	

Response

The implementation plan notes that "the proposed reliability standard PRC-030-1 includes the analytics and CAPs that complement Project 2020-02, which proposes new Reliability Standard PRC-029-1 addressing Ride-through and performance requirements for IBRs." Additionally, the DT believes that the implementation plan is clear regarding effective dates – as noted in the plan, "Where approved by an applicable governmental authority is not required, Reliability Standard PRC-030-1 shall become effective on the later of 1) the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees; or 2) the first day of the first calendar quarter that is twelve (12) months after the date Reliability Standard PRC-029-1 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction."

Thank you for the comment around the four second window, there are examples in the technical rationale that further explains examples and what qualifies or how the DT views events in relation to the four second window.

Requirement R2 is clear that the GO needs to provide requested data to the requesting reliability entity.

The RC, BA and TOP are ultimately responsible for the operation and security of the BES and BPS. As such they are accountable to know and understand the limitations and issues in the electric system, requiring knowledge of respective Corrective Action Plans.
With Requirement R4, the DT felt the CAP only had to go to the RC for the purposes of updating the timelines. This was to relieve the administrative burden on the GO's when submitting the CAP.

PRC-004 requires 60 days to develop a CAP and from comments received the DT determined to follow a similar timeline as PRC-004 when developing the CAP for PRC-030, these dates ensures reliability in PRC-004 and the team wanted to make sure that this continues to ensure reliability in PRC-030 .

End of Report

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reminder

Standards Announcement

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

Additional Ballots and Non-binding Poll Open through September 13, 2024

Now Available

Additional ballots for draft four of **PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Friday, September 13, 2024**.

This will be the last opportunity for NERC to ballot this project. This standard had minor changes from the last passing ballot. One change was in the Applicability section, removing "Elements associated with" from the Facilities section. The drafting team also made very minor changes, based on comments received, that were necessary. Another change for this posting is in regard to the PRC-030-1 Implementation Plan, to provide better clarity.

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.

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 Standards Developer, Josh Blume (via email) or at 470-755-0346. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues observer list” in the Description Box.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

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

Formal Comment Period Open through September 13, 2024

Now Available

A 17-day formal comment period for draft four of **PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation** is open through **8 p.m. Eastern, Friday, September 13, 2024**.

This will be the last opportunity for NERC to ballot this project. This standard had minor changes from the last passing ballot. One change was in the Applicability section, removing "Elements associated with" from the Facilities section. The drafting team also made very minor changes, based on comments received, that were necessary. Another change for this posting is in regard to the PRC-030-1 Implementation Plan, to provide better clarity.

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

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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 **September 4-13, 2024**.

For 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 470-755-0346. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues observer list” in the Description Box.

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Dashboard

NERC Standards Balloting System

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Ballot Results

Comment: View Comment Results
Ballot Name: 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Implementation Plan AB 4 OT
Voting Start Date: 9/4/2024 12:01:00 AM
Voting End Date: 9/13/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 4
Total # Votes: 245
Total Ballot Pool: 278
Quorum: 88.13
Quorum Established Date: 9/13/2024 2:03:01 PM
Weighted Segment Value: 74.56

Actions

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	76	1	37	0.725	14	0.275	0	17	8
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	60	1	34	0.694	15	0.306	0	7	4
Segment: 4	13	1	6	0.6	4	0.4	0	2	1
Segment: 5	70	1	32	0.681	15	0.319	0	9	14
Segment: 6	44	1	23	0.697	10	0.303	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: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.5	5	0.5	0	0	0	1	1
Totals:	278	6.3	145	4.697	58	1.603	0	42	33

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Third-Party Comments
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A

1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		Abstain	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Barbara Marion		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
6	AEP	Mathew Miller		Abstain	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
5	American Municipal Power	Amy Ritts		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Third-Party Comments

1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Negative	Comments Submitted
4	DTE Energy	Patricia Ireland		Negative	Comments Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Abstain	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
6	Manitoba Hydro	Brandin Stoesz		Affirmative	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Third-Party Comments
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	None	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A

3	New York Power Authority	Richard Machado		Negative	Third-Party Comments
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Third-Party Comments
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
6	Great River Energy	Brian Meloy		None	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted
5	NextEra Energy	Richard Vendetti		Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	Constellation	Alison MacKellar		None	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		None	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
1	Eversource Energy	Joshua London		Abstain	N/A

3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Third-Party Comments
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
3	Entergy	James Keele		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
1	New York Power Authority	Daniel Valle		Negative	Third-Party Comments
1	Duke Energy	Katherine Street	Ellese Murphy	Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
6	Muscatine Power and Water	Nicholas Burns		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
5	Muscatine Power and Water	Chance Back		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		None	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A

5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		None	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Third-Party Comments
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
4	Austin Energy	Tony Hua		Abstain	N/A
5	Austin Energy	Michael Dillard		None	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A

5	Tennessee Valley Authority	Darren Boehm		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Third-Party Comments
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		None	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		None	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
5	Enel Green Power	Natalie Johnson		None	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
3	Seminole Electric Cooperative, Inc.	Usama Tahir		Negative	Comments

					Submitted
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		None	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		None	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
1	JEA	Joseph McClung		Negative	Third-Party Comments
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Leo Bernier		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	JEA	John Babik		None	N/A
5	Great River Energy	Jacalynn Bentz		None	N/A
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A

1	M and A Electric Power Cooperative	William Price	Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins	Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth	Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund	Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson	Negative	Third-Party Comments
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas	None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber	Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang	Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu	Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan	Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos	Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer	None	N/A

Ballot Results

Ballot Name: 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues PRC-030-1 | Non-binding Poll AB 4 NB
Voting Start Date: 9/4/2024 12:01:00 AM
Voting End Date: 9/13/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 4
Total # Votes: 224
Total Ballot Pool: 262
Quorum: 85.5
Quorum Established Date: 9/13/2024 2:18:59 PM
Weighted Segment Value: 63.25

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	73	1	29	0.69	13	0.31	22	9
Segment: 2	7	0.5	5	0.5	0	0	2	0
Segment: 3	56	1	24	0.6	16	0.4	11	5
Segment: 4	13	1	5	0.5	5	0.5	2	1
Segment: 5	66	1	22	0.579	16	0.421	12	16
Segment: 6	41	1	15	0.577	11	0.423	8	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: 10	6	0.5	5	0.5	0	0	1	0
Totals:	262	6	105	3.946	61	2.054	58	38

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Comments Submitted
					Comments

3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Submitted
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke		Abstain	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Barbara Marion		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
6	AEP	Mathew Miller		Abstain	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Comments Submitted
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Comments Submitted
					Comments

1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Abstain	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Negative	Comments Submitted
4	DTE Energy	Patricia Ireland		Negative	Comments Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Abstain	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	None	N/A
5	Platte River Power Authority	Jon Osell		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
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A

6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
6	Great River Energy	Brian Meloy		None	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	Constellation	Alison MacKellar		None	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		None	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
1	Eversource Energy	Joshua London		Abstain	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A

10	Northeast Power Coordinating Council	Gerry Dunbar		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
3	Entergy	James Keele		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
1	Duke Energy	Katherine Street	Ellese Murphy	Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Comments Submitted
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
6	Muscatine Power and Water	Nicholas Burns		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Abstain	N/A
5	Muscatine Power and Water	Chance Back		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		None	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Comments Submitted
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		None	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle		None	N/A

		McCartney Longo			
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
4	Austin Energy	Tony Hua		Abstain	N/A
5	Austin Energy	Michael Dillard		None	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A

1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		None	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		None	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
5	Enel Green Power	Natalie Johnson		None	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		Negative	Comments Submitted
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
	Southern Company - Southern Company				

6	Generation	Ron Carlsen		None	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		None	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
1	JEA	Joseph McClung		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Leo Bernier		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	JEA	John Babik		None	N/A
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A

6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer	None	N/A

[redacted]

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-030-1 is posted for a 5-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 25, 2023
SAR posted for comment	February 22, 2023 – March 23, 2023
25-day formal comment period with ballot	March 25, 2024 – April 18, 2024
34-day formal comment period with additional ballot	June 7, 2024 – July 10, 2024
22-day formal comment period with additional ballot	July 22, 2024 – August 12, 2024
17-day formal comment period with additional ballot	August 28 – September 13, 2024

Anticipated Actions	Date
5-day final ballot	September 23 –27, 2024
Board adoption	October 8-9, 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:** Unexpected Inverter-Based Resource Event Mitigation
2. **Number:** PRC-030-1
3. **Purpose:** Identify, analyze, and mitigate unexpected Inverter-Based Resource (IBR) change of power output.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Generator Owner
   - **4.2. Facilities:**
     - **4.2.1.** Bulk Electric System (BES) Inverter-Based Resources; and
     - **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.
5. **Effective Date:** See Implementation Plan for PRC-030-1

B. Requirements and Measures

R1. Each applicable Generator Owner shall implement a documented process 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 4 second period. Changes in Real Power for the following are excluded: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- 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.

M1. Each applicable Generator Owner shall have evidence which includes but is not limited to: (1) the documented process for detecting changes in output as described in Requirement R1, (2) evidence to demonstrate implementation of its documented process, (3) actual data recordings, and (4) identification of gross nameplate rating.

R2. Each applicable Generator Owner, within 90 calendar days of a Real Power change event pursuant to Requirement R1 or following a request from its associated Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the Inverter-Based Resource(s) Real Power output, shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. Analyze its Inverter-Based Resource facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in Real Power output;

2.1.2. Document the facility's Ride-through performance including Reactive Power response during the event;

2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities.

2.2. Upon request, provide the analysis results to the requesting associated Reliability Coordinator, Balancing Authority, or Transmission Operator.

M2. Each applicable Generator Owner shall have dated documentation of the required analysis developed in accordance with Requirement R2. Evidence may include, but is not limited to: (1) an analysis report, (2) actual data recordings or derivations, (3) documents describing the device specification and device configuration or settings, and (4) plant configuration.

R3. If performance issues and a need for corrective actions were identified in Requirement R2 Part 2.1.3, each applicable Generator Owner shall, within 60 calendar days of completing the analysis in Requirement R2, develop one of the following and provide it to the associated Reliability Coordinator, Balancing Authority, and Transmission Operator: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- A Corrective Action Plan (CAP) for the identified Inverter-Based Resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R2 Part 2.1.3; or
- A technical justification that addresses why corrective actions will not be implemented.

M3. Each applicable Generator Owner shall have dated evidence (electronic or hardcopy format) that demonstrates it developed a CAP or a technical justification, and evidence of transmittal to the Reliability Coordinator, Balancing Authority, and Transmission Operator in accordance with Requirement R3.

R4. Each applicable Generator Owner shall, for each of its Corrective Action Plans developed pursuant to Requirement R3: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

4.1. Implement the CAP;

4.2. Update the CAP if actions or timetables change; and

4.3. Notify each associated Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

M4. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, communication with equipment manufacturers, and communication with each associated Reliability Coordinator that documents the implementation, updating, or completion of a CAP in accordance with Requirement R3.

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 shall keep data or evidence of Requirement R1, and R2, Measure M1, and M2 for 36 calendar months following the completion of each Requirement.
- The Generator Owner shall retain evidence of Requirement R3, Measure M3, including any supporting analysis per Requirements R2 and R3, for a minimum of 36 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.
- The Generator Owner shall retain evidence of Requirement R4, Measure M4 for a minimum of 36 calendar months following completion of each CAP.

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 responsible entity failed to implement a documented process to identify changes in Real Power output in accordance with Requirement R1.
R2.	The responsible entity performed an analysis in accordance with Requirement R2, but in more than 90 calendar days but less than 120 calendar days of an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 120 or more calendar days but less than 150 calendar days of an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 150 or more calendar days but less than 180 calendar days of an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 or Part 2.1.4. OR The responsible entity failed to provide the analysis results from the requesting entity in accordance with Requirement R2, Part 2.2.	The responsible entity developed an analysis in accordance with Requirement R2, but in 180 calendar days or more of an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 and Part 2.1.4. OR The responsible entity failed to document the facility's Ride-through performance in accordance with Requirement R2, Part 2.1.2 OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The responsible entity failed to determine the applicability of other Inverter-Based Resource facilities in accordance with Requirement R2, Part 2.1.4.
R3.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 60 calendar days, but provided it within 90 calendar days.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 90 calendar days, but provided it within 120 calendar days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 120 calendar days, but provided it within 150 calendar days OR The developed CAP did not include corrective actions for other facilities owned by the Generator Owners as identified in Requirement R2 Part 2.1.3, if necessary. OR The developed CAP or technical justification was not provided to the associated Reliability Coordinator, Balancing Authority, and Transmission Operator.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented, within 150 calendar days.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R4.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan.

Version History

Version	Date	Action	Change Tracking
Initial Draft	**02/06/2024**	**Draft**	
Second Draft	**06/07/2024**	**Draft**	
Third Draft	**07/22/2024**	**Draft**	
Fourth Draft	**08/28/2024**	**Draft**	

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Description of Current Draft

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Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 25, 2023
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Term(s):

None

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1. **Title:** Unexpected Inverter-Based Resource Event Mitigation
2. **Number:** PRC-030-1
3. **Purpose:** Identify, analyze, and mitigate unexpected Inverter-Based Resource (IBR) change of power output.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Generator Owner
   - **4.2. Facilities:**
     - **4.2.1.** Bulk Electric System (BES) Inverter-Based Resources; and
     - **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.
5. **Effective Date:** See Implementation Plan for PRC-030-1

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- Resource dispatch, resource ramping, planned outages, or planned resource testing;
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- Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.

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2.1.1. Determine the root cause(s) of change(s) in Real Power output;

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2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the applicability of the root cause(s) to the Generator Owner’s other Inverter-Based Resource facilities.

2.2. Upon request, provide the analysis results to the requesting associated Reliability Coordinator, Balancing Authority, or Transmission Operator.

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- A Corrective Action Plan (CAP) for the identified Inverter-Based Resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R2 Part 2.1.3; or
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4.1. Implement the CAP;

4.2. Update the CAP if actions or timetables change; and

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Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The responsible entity failed to implement a documented process to identify changes in Real Power output in accordance with Requirement R1.
R2.	The responsible entity performed an analysis in accordance with Requirement R2, but in more than 90 calendar days but less than 120 calendar days of an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 120 or more calendar days but less than 150 calendar days of an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 150 or more calendar days but less than 180 calendar days of an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 or Part 2.1.4. OR The responsible entity failed to provide the analysis results from the requesting entity in accordance with Requirement R2, Part 2.2.	The responsible entity developed an analysis in accordance with Requirement R2, but in 180 calendar days or more of an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 and Part 2.1.4. OR The responsible entity failed to document the facility's Ride-through performance in accordance with Requirement R2, Part 2.1.2 OR

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				The responsible entity failed to determine the ~~susceptibility~~ applicability of other I~~i~~nverter-B~~b~~ased R~~r~~esource facilities in accordance with Requirement R2, Part 2.1.4~~3~~.
R3.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 60 calendar days, but provided it within 90 calendar days.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 90 calendar days, but provided it within 120 calendar days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 120 calendar days, but provided it within 150 calendar days OR The developed CAP did not include corrective actions for other facilities owned by the Generator Owners as identified in Requirement R2 Part 2.1.3, if necessary. OR The developed CAP or technical justification was not provided to the associated Reliability Coordinator, Balancing Authority, and Transmission Operator.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented, within 150 calendar days.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R4.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan.

Version History

Version	Date	Action	Change Tracking
Initial Draft	**02/06/2024**	**Draft**	
Second Draft	**06/07/2024**	**Draft**	
Third Draft	**07/22/2024**	**Draft**	
Fourth Draft	**08/28/2024**	**Draft**	

Implementation Plan

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1

Applicable Standard(s)

- PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation

Requested Retirement(s)

- None

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Resources
- Ride-through
- Inverter-Based Resource (IBR)

Applicable Entities

- Generator Owner (GO)

Background

Multiple NERC disturbance reports,[1] including the Odessa disturbance report,[2] identified the undesired performance of Bulk Power System (BPS)-connected Inverter-Based Resources (IBR) during grid faults and have elaborated on the systemic and significant BPS reliability risks that this undesired performance can pose. IBRs may trip for many different reasons, may cease current injection due to inverter controls, or may have unwanted plant-level controller interactions. These types of issues have been extensively documented in the NERC reports. The resulting unexpected and unwarranted loss of generation poses a significant risk to BPS reliability. Project 2023-02 was initiated to address the reliability-related need and benefit by requiring analysis and mitigation of unexpected or unwarranted protection and control operations from Inverter-Based Resources (IBR) following the identification of such a performance issue.

1 https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx
2 https://www.nerc.com/pa/rrm/ea/Pages/May-June-2021-Odessa-Disturbance.aspx

In October 2023, FERC issued Order No. 901,[3] which directs the development of new or modified reliability standards, including 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[4]. Within the work plan, NERC identified three active Standards Development Projects that would need to be filed for regulatory approval with FERC November 4, 2024. These projects include 2020-02 Modifications to PRC-024 (Generation Ride Through),[5] 2021-04 Modifications to PRC-002-2,[6] and 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues.[7]

Project 2023-02

Proposed Reliability Standard PRC-030-1 is a new Reliability Standard that requires the Generator Owner to identify, analyze, and mitigate IBR performance issues. The scope of this project was adjusted to align with associated regulatory directives from FERC Order No. 901 and the scope of other projects related to "Milestone 2" of the NERC work plan. Specifically, Reliability Standard PRC-030-1 includes four (4) Requirements that require Generator Owners to: (1) define how events are to be identified, along with exceptions that should not be identified; (2) analyze identified events; (3) create a Corrective Action Plan (CAP) or technical justification when corrective actions are needed; and (4) mitigate performance risk through CAP implementation.

Proposed Reliability Standard PRC-030-1 includes the analytics and CAPs that complement Project 2020-02, which proposes new Reliability Standard PRC-029-1 addressing Ride-through and performance requirements for IBRs. The corresponding new data recording requirements are covered in Project 2021-04 and the new PRC-028-1 Reliability Standard.

General Considerations

This implementation plan recognizes the urgent need for Reliability Standards to address IBR CAPs to reduce disturbances, as demonstrated by multiple event reports of the last decade, while providing a reasonable period for entities to develop the necessary procedures and change their protection and control settings to meet the new requirements. The Electric Reliability Organization (ERO) Enterprise acknowledges that while there are IBR currently in operation, a standard is not in place that addresses CAPs for IBR.

[3] *Reliability Standards to Address Inverter-Based Resources,* Order No.901, 185 FERC ¶ 61,042 (2023); https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false

[4] *See Informational Filing of the N. Am. Elec. Reliability Corp. Regarding the Development of Reliability Standards Responsive to Order No. 901.*, Docket No. RM22-12-000 (January 18, 2024).

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

[6] *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

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

The ERO Enterprise acknowledges that Generator Owners and Generator Operators owning or operating BPS 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-030-1'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 BPS.

This implementation plan requires that all BES IBRs fully comply with the requirements by the effective date. It requires that applicable non-BES IBRs[8] comply by the later of: (1) January 1, 2027; or (2) the effective date of the standard.

Effective Date

The effective date for the proposed Reliability Standard is provided below.

Standard PRC-030-1

Where approval by an applicable governmental authority is required, Reliability Standard PRC-030-1 shall become effective on the 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, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard PRC-030-1 shall become effective on the later of 1) the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees; or 2) the first day of the first calendar quarter that is twelve (12) months after the date Reliability Standard PRC-029-1 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

[8] The facilities section of the standard applies to "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."

PRC-030-1 Phased-in Compliance Dates

Requirements R1, R2, R3, and R4

Bulk Electric System IBRs

Bulk Electric System IBRs shall initially comply with all Requirements by the effective date of the standard.

Applicable Non-BES IBRs

Applicable Non-BES Inverter-Based Resources shall initially comply with Requirements R1, R2, R3, and R4 by the later of: (1) January 1, 2027; or (2) the effective date of the standard. Applicable Non-BES Inverter-Based Resources include 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.

Implementation Plan

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1

Applicable Standard(s)

- PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation

Requested Retirement(s)

- None

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based ~~Generating~~ Resources
- Ride-through
- Inverter-Based Resource (IBR)

Applicable Entities

- Generator Owner (GO)

Background

Multiple NERC disturbance reports,[1] including the Odessa disturbance report,[2] identified the undesired performance of Bulk Power System (BPS)-connected I~~i~~nverter-B~~b~~ased R~~r~~esources (IBR~~s~~) during grid faults and have elaborated on the systemic and significant BPS reliability risks that this undesired performance can pose. IBRs may trip for many different reasons, may cease current injection due to inverter controls, or may have unwanted plant-level controller interactions. These types of issues have been extensively documented in the NERC reports. The resulting unexpected and unwarranted loss of generation poses a significant risk to BPS reliability. Project 2023-02 was initiated to address the reliability-related need and benefit by requiring analysis and mitigation of unexpected or unwarranted protection and control operations from Inverter-Based Resources (IBR) following the identification of such a performance issue.

1 https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx
2 https://www.nerc.com/pa/rrm/ea/Pages/May-June-2021-Odessa-Disturbance.aspx

In October 2023, FERC issued Order No. 901,[3] which directs the development of new or modified reliability standards, including 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[4]. Within the work plan, NERC identified three active Standards Development Projects that would need to be filed for regulatory approval with FERC November 4, 2024. These projects include 2020-02 Modifications to PRC-024 (Generation Ride Through),[5] 2021-04 Modifications to PRC-002-2,[6] and 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues.[7]

Project 2023-02
Proposed Reliability Standard PRC-030-1 is a new Reliability Standard that requires the Generator Owner to identify, analyze, and mitigate IBR performance issues. The scope of this project was adjusted to align with associated regulatory directives from FERC Order No. 901 and the scope of other projects related to "Milestone 2" of the NERC work plan. Specifically, Reliability Standard PRC-030-1 includes four (4) Requirements that require Generator Owners to: (1) define how events are to be identified, along with exceptions that should not be identified; (2) analyze identified events; (3) create a Corrective Action Plan (CAP) or technical justification when corrective actions are needed; and (4) mitigate performance risk through CAP implementation.

Proposed Reliability Standard PRC-030-1 includes the analytics and CAPs that complement Project 2020-02, which proposes new Reliability Standard PRC-029-1 addressing Ride-through and performance requirements for IBRs. The corresponding new data recording requirements are covered in Project 2021-04 and the new PRC-028-1 Reliability Standard.

General Considerations

This implementation plan recognizes the urgent need for Reliability Standards to address IBR CAPs to reduce disturbances, as demonstrated by multiple event reports of the last decade, while providing a reasonable period for entities to develop the necessary procedures and change their protection and control settings to meet the new requirements. The Electric Reliability Organization (ERO) Enterprise acknowledges that while there are IBR currently in operation, a standard is not in place that addresses CAPs for IBR.

[3] *Reliability Standards to Address Inverter-Based Resources,* Order No.901, 185 FERC ¶ 61,042 (2023); https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false
[4] *See Informational Filing of the N. Am. Elec. Reliability Corp. Regarding the Development of Reliability Standards Responsive to Order No. 901.*, Docket No. RM22-12-000 (January 18, 2024).
[5] *See* NERC Standards Development Project page for Project 2002-02; https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx
[6] *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
[7] *See* NERC Standards Development Project page for Project 2023-02; https://www.nerc.com/pa/Stand/Pages/Project-2023-02-Performance-of-IBRs.aspx

The ERO Enterprise acknowledges that Generator Owners and Generator Operators owning or operating BPS 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-030-1'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 BPS.

This implementation plan requires that all BES IBRs fully comply with the requirements by the effective date. It requires that applicable non-BES IBR~~S~~s[8] comply by the later of: (1) January 1, 2027; or (2) the effective date of the standard.

Effective Date

The effective date for the proposed Reliability Standard is provided below.

Standard PRC-030-1

Where approval by an applicable governmental authority is required, Reliability Standard PRC-030-1 shall become effective on the 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, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard PRC-030-1 shall become effective on the later of 1) the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees; or 2) the first day of the first calendar quarter that is twelve (12) months after the date Reliability Standard PRC-029-1 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

[8] The facilities section of the standard applies to ~~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."

PRC-030-1 Phased-in Compliance Dates

Requirements R1, R2, R3, and R4

Bulk~~-~~ Electric System IBRs

Bulk Electric System IBRs~~S~~ shall initially comply with all Requirements by the effective date of the standard.

Applicable Non-BES IBRs

Applicable Non-BES Inverter-Based Resources shall initially comply with Requirements R1, R2, R3, and R4 by the later of: (1) January 1, 2027; or (2) the effective date of the standard. Applicable Non-BES ~~i~~Inverter-~~b~~Based ~~r~~Resources include non-BES I~~i~~nverter-B~~b~~ased ~~r~~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.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Technical Rationale

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1 | September 2024

PRC-030-1 – Unexpected Inverter-Based Resource Event Mitigation

Rationale for Applicability Section
The functional entity responsible for identifying, analyzing, and mitigating unexpected Inverter Based Resources (IBR) performance is the Generator Owner (GO). The Generator Operator (GOP) is not included because of the accountability and coordination issues introduced by listing both GO and GOP as responsible functional entities. The GO is accountable for changes and improvements to the IBR and facilities necessary to mitigate performance problems. Further, this standard intentionally did not include requirements for the Balancing Authority (BA), Reliability Coordinator (RC), and Transmission Operator (TOP) because other standards (e.g., EOP-004) place requirements on these entities for system level events.

General rationale
Aligned with the Project 2023-02 Standards Authorization Request (SAR), the Requirements are structured to identify, analyze, and mitigate IBR performance issues. The SAR discusses how a series of NERC disturbance reports have "identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that these pose". [1,] In particular, IBR performance during events has included tripping or momentary cessation that is unexpected, unwarranted, and poses reliability challenges.

Requirement R1 defines how events are to be identified, along with exceptions that should not be identified. Requirement R2 requires analysis of identified events, with specific elements assessed as described in subparts. Requirement R3 requires a Corrective Action Plan (CAP) or technical justification when corrective actions are needed. Finally, R4 requires mitigation of the performance risk through CAP implementation. The flow of these requirements is summarized in Figure 1.1.

[1] *Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Standard Authorization Request, at p. 1 (accepted August 23, 2023) (referencing Event Reports (nerc.com))*

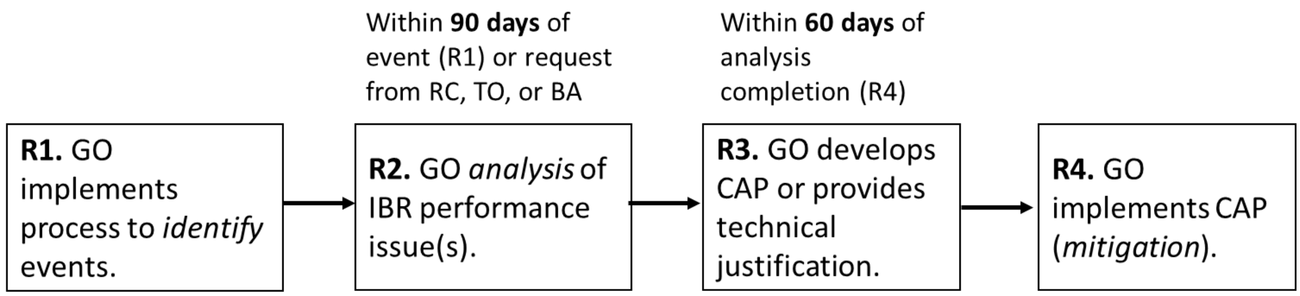


Figure 1.1: Relationship of Requirements in PRC-030-1

The Requirement R1 contains thresholds for identifying events with sudden changes in Real Power. Figure 1.2 depicts the threshold criteria and logic used in Requirement R1, along with additional details of process flow in Requirement R2.

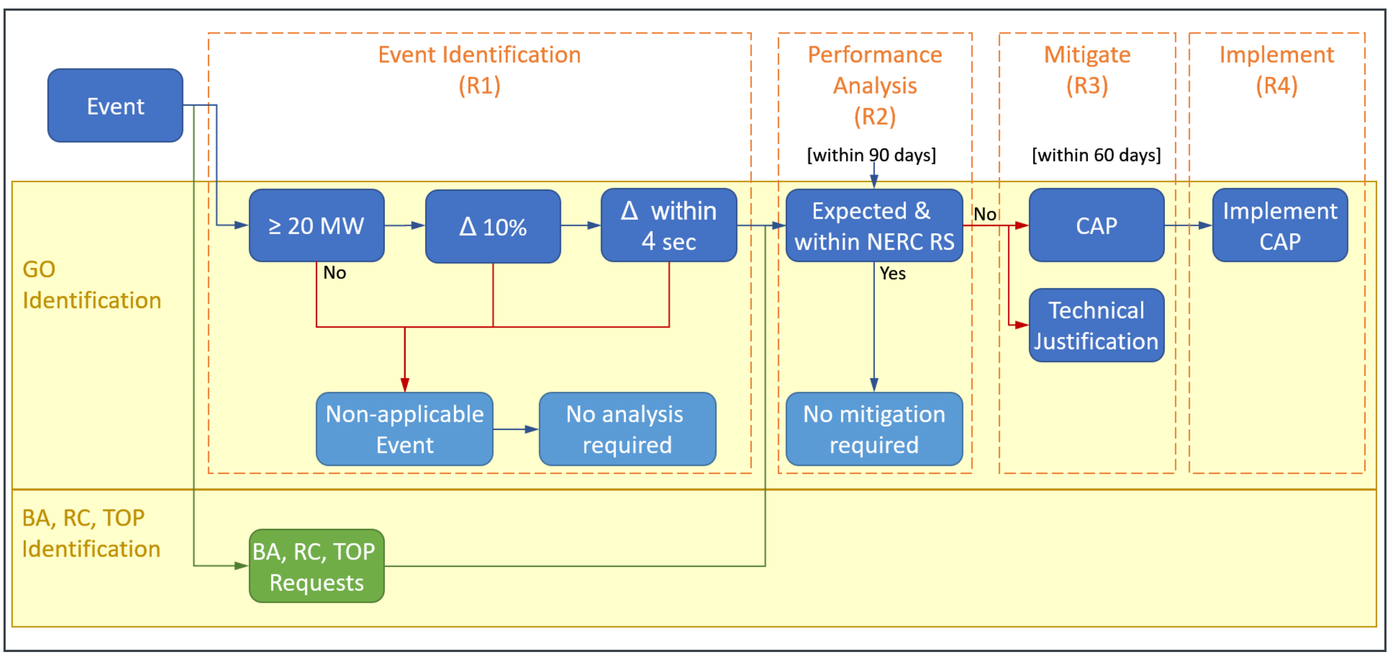


Figure 1.2: PRC-030-1 Flowchart

Rationale for Requirement R1

The intent of Requirement R1 is for the Generator Owner (GO) to implement a documented process to self-identify events that are sufficiently large to warrant an analysis of IBR performance for the identified event. For that reason, the Drafting Team included the 20 MW minimum threshold, which is a common

cutoff for other Reliability Standards, such as MOD-025, to reduce the number of potential events. NERC Category two in the ROP, entity registration section references 20 MVA as a significant threshold.

While the GO should consider both active and reactive power responses when an analysis is required, only Real Power is used as a threshold to trigger analysis. Real Power was selected as the monitored parameter to make implementation feasible across IBR plant designs and back end software system (e.g., SCADA). MW and Mvar are monitored on the SCADA software, while MVA is typically not present. The Drafting Team (DT) went with MW instead of MVA due to Real power loss being the primary concern in IBR events.

The thresholds for event identification in Requirement R1 provide a two-tier approach depending on the size of the IBR facility. The table below shows the two tiers and the thresholds that should be used to identify events. In addition, all unexpected events in which there is a complete loss of MW output, or active drops to 0 MW, should be identified regardless of plant size and output. This of course excludes planned ramp downs, and all other exclusions listed in Requirement R1 (solar end of day ramp down, planned outages, loss of connecting transmission facilities, Misoperations identified in PRC-004, etc.).

Facility Nameplate Rating	**Threshold**
200 MW or less	20 MW
Greater than 200 MW	10% of Nameplate Rating (e.g. 30 MW for 300 MW Facility)

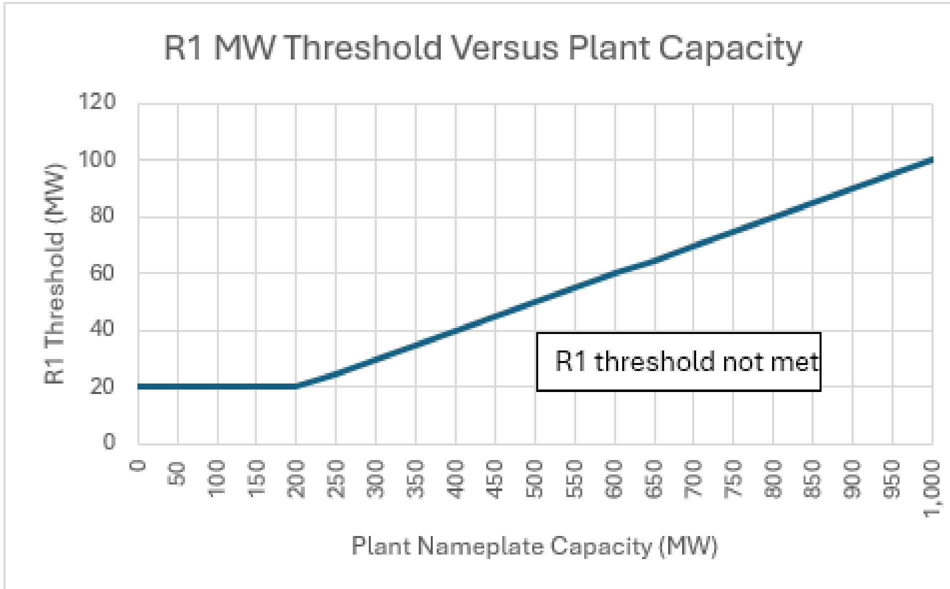
Nameplate rating was used as the basis of the change (power or amperes) because it is the common reference in NERC and other industry standards. Nameplate was chosen because every generator has a nameplate rating that can be referenced. Nameplate rating is also included as the reference point as it is included in the BES definition.

The 10% of nameplate rating for magnitude of Real Power change event threshold was chosen to be large enough to screen out small Real Power changes but low enough to detect events that should be analyzed for reliability purposes. The percent change is intended to address facilities with greater than 200 MW nameplate rating where 10% is a significant change, otherwise the 20 MW threshold sets a minimum threshold for event identification. The 20 MW minimum change threshold causes the 10% change to only apply to 200 MW facilities and above.
For smaller capacity facilities, the use of only a percent change as the screening criteria would lead to identification of disturbances that are not likely to be significant for analysis.

To restate the criteria another way:

- For plants with 0 – 200 MW gross nameplate rating, the change must be at least 20 MW,
- For plants with 200 MW gross nameplate rating and larger, the change must be at least 10% of the gross nameplate rating.

The criteria could be charted as depicted below.



Requirement R1 Threshold met

The purpose of the two limits is to make the trigger points manageable for both large and small facilities. The Drafting Team (DT) recognizes that as the plant size grows, so does the trigger threshold, which is why the threshold was set at 10% rather than something larger, like 20%. While the GO would not be required to identify events below the 10% threshold for large plants, the Reliability Coordinator (RC) is explicitly given the option to request a review in the requirement.

The DT revised the wording of Requirement R1 to clarify that the DT's intent is at least 20 MW for facilities with a nameplate rating of 200 MW or less and at least 10% change for facilities with a nameplate rating over 200 MW. While the DT considered the existing criteria sufficient, a complete loss of the facility was also included as a Requirement R1 condition.

At one point, the DT considered using the terms "sudden" and "unexpected", but that created uncertainty and concerns about consistent application. Therefore, the DT chose to bound the initial change at event onset to a four second timeframe.

The various SCADA scan rates in use at ISOs/RTOs as well as NERC standard minimum required scan rates were considered in selecting four seconds. SCADA monitoring is a likely method for monitoring Real Power changes. Power changes that occur and recover within one scan are not expected to be detected by the Requirement R1 process implemented by GOs. The four seconds was not intended to define the scan period, but only to characterize the change as sudden when considering information on monitoring capabilities across the industry. If a facility is using a scan rate of four seconds or greater to monitor Real Power output, the GO should use the change in Real Power output in one scan rate to identify events meeting Requirement R1 criteria. It should be noted that using longer time periods or scan rate could lead

to a need for more sophisticated event screening or may otherwise lead to identification of more invalid events that occur on slower timescales.

The intention of the four seconds was to limit the time within which the change in Real Power is calculated. The DT also considered that IBR generation plants following normal operation dispatch commands tend to move more slowly. For example, using the 20 MW for four seconds, the change rate is 5MW/sec, or 300 MW/min. Lower ramp rates would not be expected to meet the Requirement R1 criteria.

The following set of charts, in Figure 1.4, are examples of expected event scenarios and whether they meet the Requirement R1 criteria.

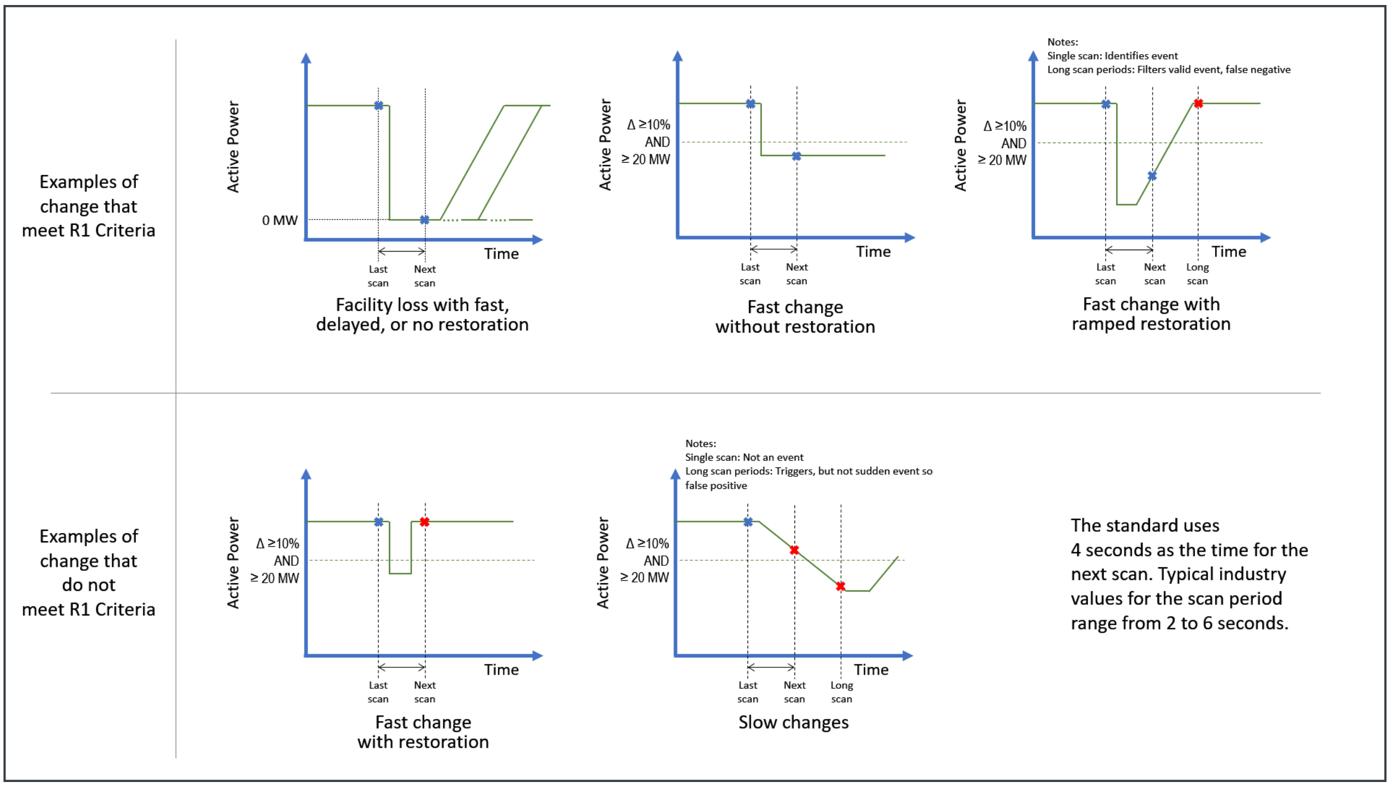


Figure 1.4: PRC-030-1 Flowchart

Due to concern voiced by industry that the thresholds defined in Requirement R1 could be often exceeded during the normal operation of an IBR facility, the DT examined three IBR facilities in Texas to determine the frequency of such events.

Solar facility in West Texas with 160 MW nameplate rating:
The DT analyzed one year of data encompassing all of 2023 and found five instances in which the facility changed 20 MW or more within a four second period. All five instances were related to ride-through performance issues previously identified by the Reliability Coordinator. There were zero events in which

Real Power changed 20 MW or more within a four second period due to change of irradiance, ramping due to dispatch, or other reasons listed as exclusions to Requirement R1.

Wind facility in Texas Panhandle with 300 MW nameplate rating:
The DT analyzed one year of data encompassing all of 2023 and found zero real events in which the facility changed 30 MW or more within a four second period. There were several events that were triggered due to dropouts of telemetry from the facility, but telemetry from the Point of Interconnection verified that there were no actual drops in Real Power from the facility at the time.

Solar Facility in Central Texas with 500 MW nameplate rating:
The DT analyzed one month of data for June 2024 and found seven events in which the facility changed 50 MW or more within a four second period, the first four of these events appear to be caused by curtailment issues. The plant was either being curtailed or was released from curtailment at the time which four of the seven events were detected. One of those events showed a large increase of irradiance at the time, but it is unclear if the change of irradiance alone caused the sudden increase in generation or if it was due to improper curtailment ramp rates, or a combination of the two. Two of the other events were related to large oscillations lasting up to an hour in which peak to peak magnitude of the oscillation exceeded 50 MW. The last event was due to a Power Plant Controller issue that caused a sudden drop in Real Power of 246 MW and was previously identified by the Reliability Coordinator. Under Requirement R1 requirements, three of the seven events would meet criteria and need to be analyzed in Requirement R2. The table below summarizes the results:

Date/Time	Four second MW change	Increase/ Decrease	Significant Irradiance Change	Cause	Should be Analyzed in R2
6/4/2024 1:25:00 PM	83	Increase	Yes	Curtailment issue/ Irradiance change?	No (Resource dispatch and/or change in irradiance exclusion)
6/4/2024 5:00:00 PM	192	Increase	No	Curtailment released	No (Resource dispatch exclusion)
6/14/2024 8:02:00 AM	57	Increase	No	Curtailment issue	No (Resource dispatch exclusion)
6/14/2024 11:36:00 AM	138	Increase	No	Curtailment issue	No (Resource dispatch exclusion)
6/17/2024 11:45:00 AM	246	Decrease	No	Plant controller issue	Yes
6/23/2024 12:30:00 PM	50	Both	No	Oscillation Event	Yes (peak to peak magnitude >50 MW observed)
6/26/2024 4:00:00 PM	78	Both	No	Oscillation Event	Yes (peak to peak magnitude >50 MW observed)

The DT also analyzed data covering one month from four facilities in Hawaii and found only one event that exceeded thresholds in Requirement R1. Since facilities in this area are generally smaller, all four facilities

analyzed were less than 200 MW in nameplate rating, so a 20 MW threshold was used for analysis. The DT also looked at an extended time period of 60 seconds, and as expected, more events were identified with the extended time period.

Plant #	1	2	3	4
Technology	Wind	PV	PV/BESS (AC Couple)	BESS Standalone
Facility Nameplate Rating (MW)	69	46	39	135
# of event (4 second, >20 MW)	0	0	0	1 (cause unknown)
# of event (60 second, >20 MW)	0	0	0	8

Due to the above analysis, the DT believes the thresholds in Requirement R1 would rarely trigger events due to normal operation of an IBR facility if the facility is operating as expected. The DT only found one possible instance of a facility exceeding the thresholds due to change of irradiance and wind speed, and it was likely caused by improper curtailment ramp rates programmed into the Power Plant Controller. In addition, the DT reviewed papers published by NREL on Solar PV Variability at Small Timescales and Variability of Wind Power Output, which concludes that change in irradiance and wind speed would not have large impacts to changes in output within a narrow timeframe such as a four second period.

The intention of the four second period was to specify what constitutes a sudden change in power, similar to the types of Real Power loss events described in NERC Disturbance Event reports. The DT considered using the term “scan period” to define the change period, because this scan period is the basis of the time, but chose to stay with the four second time specification. Four seconds is a common industry practice, MISO’s scan rate, which is one of the longest, has a time duration of four seconds. The four second threshold is meant to provide a significant exclusion because the change must occur quickly, within that time. Increasing the time effectively reduces the rate of change and would identify more events than a four second window. The intent is to exclude from review slow power changes expected with normal operations (e.g., variable output from weather, dispatch, planned outages, testing) or expected responses (e.g., loss of interconnection facilities), which were defined as bullet points to Requirement R1.

The standard four second time only applies to the period of calculating the Real Power change, such as a sudden drop, to be considered valid events identified under Requirement R1. This time does not limit or imply any duration for the entire event. While the change must occur within the four second timeframe, the plant response may take tens of seconds or even minutes. The standard does specify or limit that time period.

The term “changes in Real Power” encompasses both sudden decreases (i.e., loss of output) and increases (i.e., additional consumption) that may be caused by IBR mis-operations that could affect system

reliability. For instance, a battery energy storage system that mis-measures system frequency may unexpectedly enter a charging mode and suddenly increase Real Power draw.

Photovoltaic (PV) example 1 – qualifying:
PV facility with gross nameplate rating of 220 MW is operating with active output of 80 MW. During a transmission system fault event,[2] the plant exhibits a near instantaneous Real Power output drop to 50 MW.

The change in apparent power in under four seconds is 30 MW, which exceeds 22 MW, the greater of 10% of the plant's gross nameplate (22 MW) or 20 MW. This IBR performance event is required to be captured by the GO's process implemented in Requirement R1.

PV example 2 – non-qualifying:
PV facility with gross nameplate rating of 80 MW is operating with active output of 60 MW. During a transmission line fault event,[1] the plant exhibits a near instantaneous Real Power output drop to 42 MW.

The change in apparent power in under four seconds is 18 MW, <u>not</u> exceeding 20 MW, the greater of 10% of the plant's gross nameplate rating (8 MW) or 20 MW. This IBR performance event is <u>not</u> required to be captured by the GO's Requirement R1 process.

Battery Energy Storage System (BESS) example 1 – qualifying:
BESS facility with gross nameplate power output rating of 80 MW is operating as a load drawing 50 MW. During a power plant controller (PPC) malfunction event of the BESS facility, the PPC incorrectly estimates system frequency sending an incorrect frequency response signal causing the plant to exhibit a near instantaneous change in real power to 10 MW injection.

The change in apparent power in under four seconds is 60 MW, which exceeds 20 MW, the greater of 10% of the BESS gross nameplate (8 MW) or 20 MW.
This IBR performance event is required to be captured by the GO's Requirement R1 process.

BESS example 2 – non-qualifying:
BESS facility with gross nameplate power output rating of 80 MW is outputting 40 MW. The BESS facility is curtailed by the Reliability Coordinator such that the plant exhibits a near instantaneous Real Power decrease to 15 MW.

The change in apparent power in under four seconds is 25 MW, exceeding 20 MW, the greater of 10% of the plant's gross nameplate rating (8 MW) or 20 MW. However, the change in apparent power is the result of the Reliability Coordinator curtailment which is an exempt event per Requirement R1. This IBR performance event is <u>not</u> required to be captured by the GO's Requirement R1 process.

[2] The transmission line fault is assumed not to be on the line connecting the IBR to the system, but rather is a fault remote from the IBR.

Rationale for Requirement R2

Requirement R2 requires analysis of events that meet Requirement R1 thresholds. Requirement R2 also provides an alternative path of event identification by the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operators (TOP). It is anticipated that some events would only be detected by one entity, but the combination of both identification methods would better identify events potentially posing reliability challenges.

Requirement R2 allows 90 days to analyze expected versus actual IBR responses to place an emphasis on diligent resolution, while still allowing enough time to conduct an analysis and identify causes. Ninety days allows adequate time for GO to interact with manufacturers and examine capabilities of equipment. In establishing this timeframe, the DT considered the PRC-004 timeline of 120 days, recognizing important differences between the application of these standards. PRC-004-4(i) Technical Rationale states "The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed".[3] The PRC-004 timeframe accounts for extreme weather events such as hurricanes that may affect a very large number of Protection Systems for a given responsible entity. The volume of IBR exposed to potential expected operation is anticipated to be lower when compared to Protection Systems and therefore a shorter timeframe is appropriate for PRC-030. The 90-day period starts from the event date for GO-identified performance issues resulting from Requirement R1 or upon request from the Balancing Authority, Reliability Coordinator, or Transmission Operator regarding IBR responses identified during system events.

Requirement R2, Part 2.1 includes subparts to analyze performance during a Real power change event. Requirement R2, Part 2.1.1 requires identification of the root cause. Requirement R2, Part 2.1.2 requires that the facility's Ride-through performance including reactive power response is documented (Requirement R2, Part2.1.2). Requirement R2, Part 2.1.3 requires that the GO assess the performance issue(s) and determine whether corrective actions are needed. Requirement R2, Part 2.1.4 requires that the GO consider the applicability of the root cause to its other IBR facilities. Collectively, the subparts define the minimum features required as part of an effective analysis. Requirement R2, Part 2.2 closes the communication loop with Balancing Authority, Reliability Coordinator, and Transmission Operator entities, should these entities request analysis results.

When the root cause cannot be identified or a root cause is identified but the GO cannot fully mitigate it, then it is expected the GO will continue to work with the associated reliability entities and Original Equipment Manufacturers to follow up on such instances and deploy mitigation plans when these become available. The GO will continue to coordinate with associated reliability entities through improvements to root cause analysis and CAPs until such a time the mitigation plans are in place. Such improvements include better data capture, and fault logging capabilities for subsequent future events.

[3] Standard PRC-004-4(i) – Protection System Misoperation Identification and Correction. Available at: https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-004-4(i).pdf

Rationale for Requirement R3

Should Requirement R2 determine a need for corrective actions, Requirement R3 requires a CAP or technical justification be developed within 60 calendar days of completing the analysis in Requirement R2, as identified in Requirement R2, Part 2.1.3. If Requirement R2 did not identify the need for corrective actions, then no action is required under Requirement R3.

Resolving the causes of IBR performance issues benefits BPS reliability by preventing recurrence. The CAP is an established tool for resolving operational problems. The NERC *Glossary* defines a Corrective Action Plan as, "A list of actions and an associated timetable for implementation to remedy a specific problem." Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the IBR Performance issue cause(s) is identified in Requirement R2 or Requirement R3 requires Generator Owner(s) to develop a CAP or provide a technical justification that addresses why corrective actions will not be applied nor implemented. The CAP is provided to the Reliability Coordinator, Balancing Authority, and Transmission Operator so that these entities 1) gain information potentially relevant to recent system events, and 2) can account for potential IBR performance issues in operational risk assessments.

This standard recognizes there may be multiple causes for IBR performance issues. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a CAP to correct multiple causes of an IBR performance issue. The 60-calendar day period for developing a CAP or technical justification is established based on industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent IBR performance issues from reoccurring, the timetable for executing such actions, and an evaluation of the CAP's applicability to the GO's other IBR including those at other locations. The evaluation of these other IBR with similar designs aims to reduce the risk and the likelihood of similar IBR performance issues in other IBRs. The GO is responsible for determining the extent of its evaluation concerning other IBRs and locations. The evaluation may result in the GO including actions to address IBR at other locations or to provide a technical justification that addresses why corrective actions will not be applied nor implemented.

Acceptable technical justification for not performing corrective actions is expected to primarily have two characteristics:

1) interconnection requirements on IBR performance extending beyond those in place at the time of interconnection; and
2) it would require significant material modifications/qualified change.

Technical justifications for not performing corrective actions do not relieve the GO from compliance with other standards (i.e., PRC-029-1 Ride-Through) to the extent that other standards are applicable.

Rationale for Requirement R4

Requirement R4 requires that each applicable GO implement the CAP developed in Requirement R3, as applicable, to mitigate deficiencies identified in Requirement R2. In the NERC *Glossary*, a CAP is: “A list of actions and an associated timetable for implementation to remedy a specific problem.”

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. If the CAP is changed, the entity must notify the applicable Reliability Coordinator(s). The entity must also notify applicable RC(s) when the CAP has been completed. The implementation of a properly developed CAP ensures that causes of unexpected changes in IBR power output are mitigated in a timely manner.

An IBR deficiency may require the Reliability Coordinator to impose operating restrictions so the system can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions should incentivize the entity to complete the CAP as quickly as possible.

Technical Rationale

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1 | September 2024

PRC-030-1 – Unexpected Inverter-Based Resource Event Mitigation

Rationale for Applicability Section

The functional entity responsible for identifying, analyzing, and mitigating unexpected Inverter Based Resources (IBR) performance is the Generator Owner (GO). The Generator Operator (GOP) is not included because of the accountability and coordination issues introduced by listing both GO and GOP as responsible functional entities. The GO is accountable for changes and improvements to the IBR and facilities necessary to mitigate performance problems. Further, this standard intentionally did not include requirements for the Balancing Authority (BA), Reliability Coordinator (RC), and Transmission Operator (TOP) because other standards (e.g., EOP-004) place requirements on these entities for system level events.

General rationale

Aligned with the Project 2023-02 Standards Authorization Request (SAR), the Requirements are structured to identify, analyze, and mitigate IBR performance issues. The SAR discusses how a series of NERC disturbance reports have “identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that these pose”. [1,] In particular, IBR performance during events has included tripping or momentary cessation that is unexpected, unwarranted, and poses reliability challenges.

Requirement R1 defines how events are to be identified, along with exceptions that should not be identified. Requirement R2 requires analysis of identified events, with specific elements assessed as described in subparts. Requirement R3 requires a Corrective Action Plan (CAP) or technical justification when corrective actions are needed. Finally, R4 requires mitigation of the performance risk through CAP implementation. The flow of these requirements is summarized in Figure 1.1.

[1] *Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Standard Authorization Request, at p. 1 (accepted August 23, 2023) (referencing Event Reports (nerc.com))*

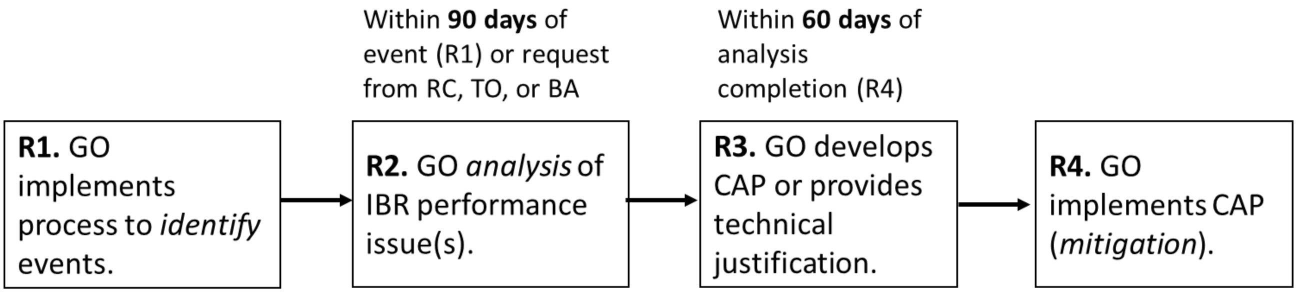


Figure 1.1: Relationship of Requirements in PRC-030-1

The Requirement R1 contains thresholds for identifying events with sudden changes in Real Power. Figure 1.2 depicts the threshold criteria and logic used in Requirement R1, along with additional details of process flow in Requirement R2.

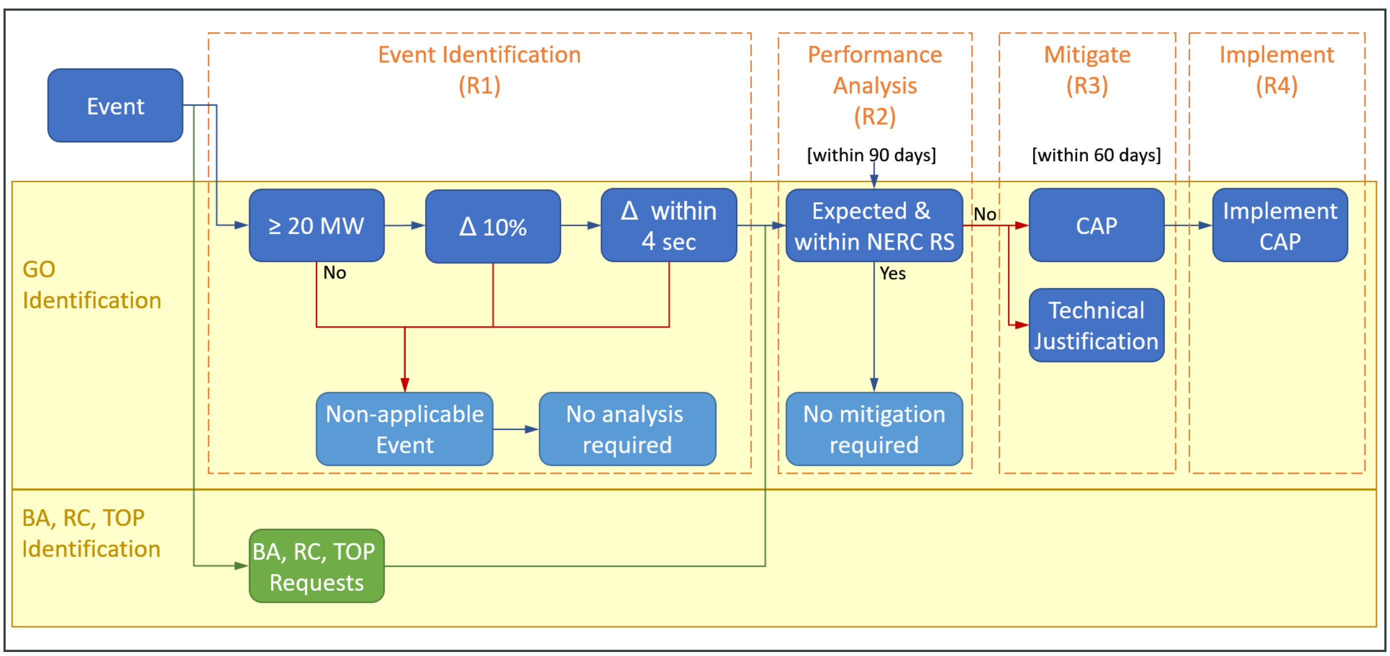


Figure 1.2: PRC-030-1 Flowchart

Rationale for Requirement R1

The intent of Requirement R1 is for the Generator Owner (GO) to implement a documented process to self-identify events that are sufficiently large to warrant an analysis of IBR performance for the identified event. For that reason, the Drafting Team included the 20 MW minimum threshold, which is a common

cutoff for other Reliability Standards, such as MOD-025, to reduce the number of potential events. NERC Category two in the ROP, entity registration section references 20 MVA as a significant threshold.

While the GO should consider both active and reactive power responses when an analysis is required, only Real Power is used as a threshold to trigger analysis. Real Power was selected as the monitored parameter to make implementation feasible across IBR plant designs and back end software system (e.g., SCADA). MW and Mvar are monitored on the SCADA software, while MVA is typically not present. The Drafting Team (DT) went with MW instead of MVA due to Real power loss being the primary concern in IBR events.

The thresholds for event identification in Requirement R1 provide a two-tier approach depending on the size of the IBR facility. The table below shows the two tiers and the thresholds that should be used to identify events. In addition, all unexpected events in which there is a complete loss of MW output, or active drops to 0 MW, should be identified regardless of plant size and output. This of course excludes planned ramp downs, and all other exclusions listed in Requirement R1 (solar end of day ramp down, planned outages, loss of connecting transmission facilities, Misoperations identified in PRC-004, etc.).

Facility Nameplate Rating	**Threshold**
200 MW or less	20 MW
Greater than 200 MW	10% of Nameplate Rating (e.g. 30 MW for 300 MW Facility)

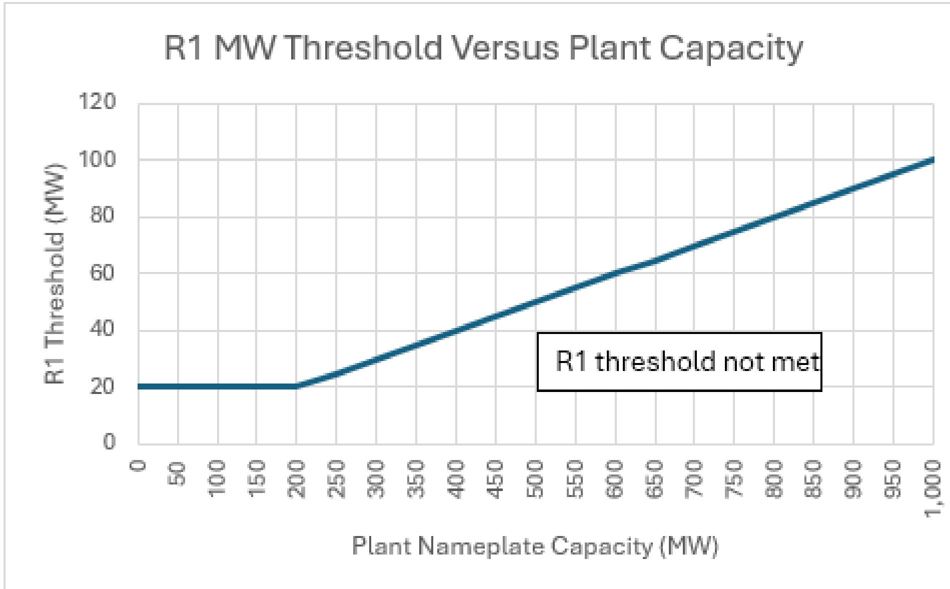
Nameplate rating was used as the basis of the change (power or amperes) because it is the common reference in NERC and other industry standards. Nameplate was chosen because every generator has a nameplate rating that can be referenced. Nameplate rating is also included as the reference point as it is included in the BES definition.

The 10% of nameplate rating for magnitude of Real Power change event threshold was chosen to be large enough to screen out small Real Power changes but low enough to detect events that should be analyzed for reliability purposes. The percent change is intended to address facilities with greater than 200 MW nameplate rating where 10% is a significant change, otherwise the 20 MW threshold sets a minimum threshold for event identification. The 20 MW minimum change threshold causes the 10% change to only apply to 200 MW facilities and above.
For smaller capacity facilities, the use of only a percent change as the screening criteria would lead to identification of disturbances that are not likely to be significant for analysis.

To restate the criteria another way:

- For plants with 0 – 200 MW gross nameplate rating, the change must be at least 20 MW,
- For plants with 200 MW gross nameplate rating and larger, the change must be at least 10% of the gross nameplate rating.

The criteria could be charted as depicted below.



Requirement R1 Threshold met

The purpose of the two limits is to make the trigger points manageable for both large and small facilities. The Drafting Team (DT) recognizes that as the plant size grows, so does the trigger threshold, which is why the threshold was set at 10% rather than something larger, like 20%. While the GO would not be required to identify events below the 10% threshold for large plants, the Reliability Coordinator (RC) is explicitly given the option to request a review in the requirement.

The DT revised the wording of Requirement R1 to clarify that the DT's intent is at least 20 MW for facilities with a nameplate rating of 200 MW or less and at least 10% change for facilities with a nameplate rating over 200 MW. While the DT considered the existing criteria sufficient, a complete loss of the facility was also included as a Requirement R1 condition.

At one point, the DT considered using the terms "sudden" and "unexpected", but that created uncertainty and concerns about consistent application. Therefore, the DT chose to bound the initial change at event onset to a four second timeframe.

The various SCADA scan rates in use at ISOs/RTOs as well as NERC standard minimum required scan rates were considered in selecting four seconds. SCADA monitoring is a likely method for monitoring Real Power changes. Power changes that occur and recover within one scan are not expected to be detected by the Requirement R1 process implemented by GOs. The four seconds was not intended to define the scan period, but only to characterize the change as sudden when considering information on monitoring capabilities across the industry. If a facility is using a scan rate of four seconds or greater to monitor Real Power output, the GO should use the change in Real Power output in one scan rate to identify events meeting Requirement R1 criteria. It should be noted that using longer time periods or scan rate could lead

to a need for more sophisticated event screening or may otherwise lead to identification of more invalid events that occur on slower timescales.

The intention of the four seconds was to limit the time within which the change in Real Power is calculated. The DT also considered that IBR generation plants following normal operation dispatch commands tend to move more slowly. For example, using the 20 MW for four seconds, the change rate is 5MW/sec, or 300 MW/min. Lower ramp rates would not be expected to meet the Requirement R1 criteria.

The following set of charts, in Figure 1.4, are examples of expected event scenarios and whether they meet the Requirement R1 criteria.

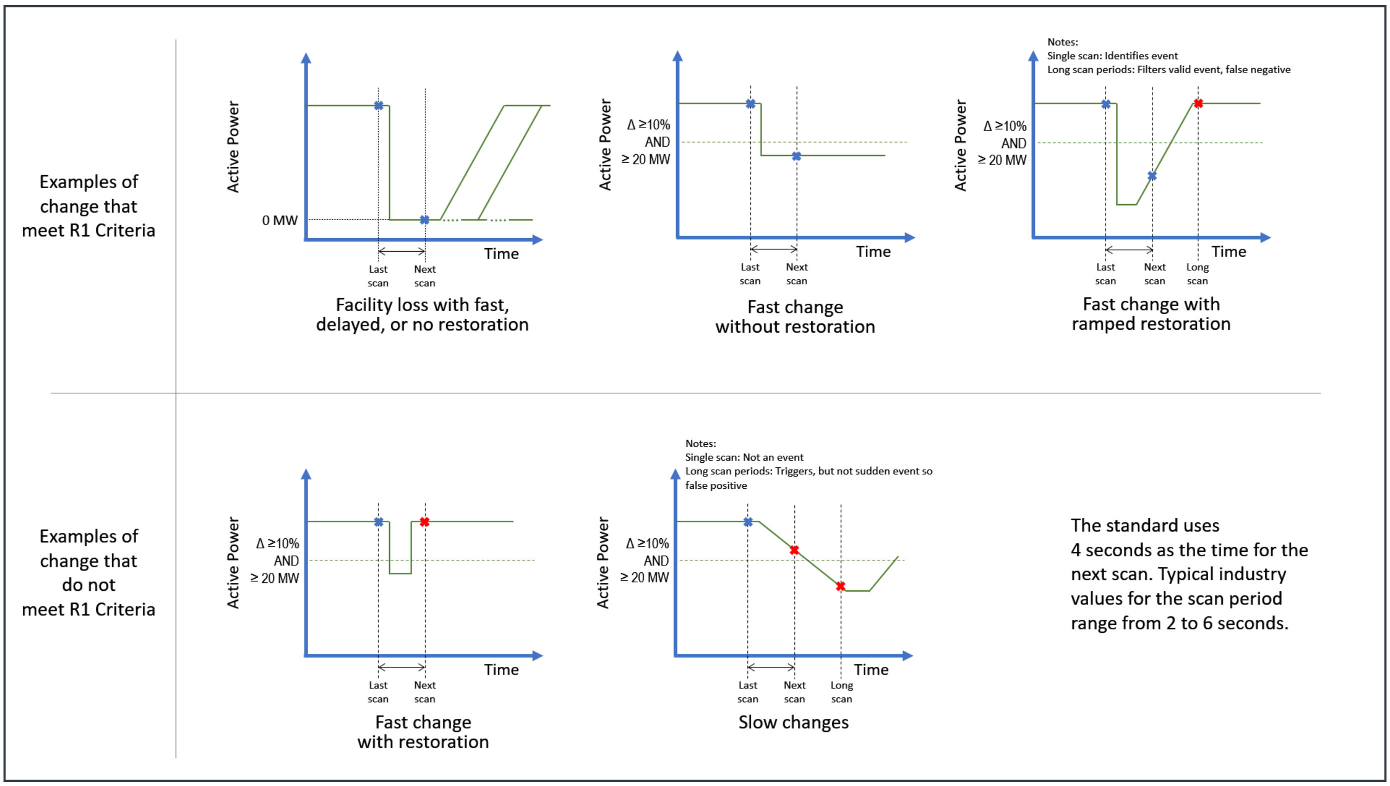


Figure 1.4: PRC-030-1 Flowchart

Due to concern voiced by industry that the thresholds defined in Requirement R1 could be often exceeded during the normal operation of an IBR facility, the DT examined three IBR facilities in Texas to determine the frequency of such events.

Solar facility in West Texas with 160 MW nameplate rating:
The DT analyzed one year of data encompassing all of 2023 and found five instances in which the facility changed 20 MW or more within a four second period. All five instances were related to ride-through performance issues previously identified by the Reliability Coordinator. There were zero events in which

Real Power changed 20 MW or more within a four second period due to change of irradiance, ramping due to dispatch, or other reasons listed as exclusions to Requirement R1.

Wind facility in Texas Panhandle with 300 MW nameplate rating:
The DT analyzed one year of data encompassing all of 2023 and found zero real events in which the facility changed 30 MW or more within a four second period. There were several events that were triggered due to dropouts of telemetry from the facility, but telemetry from the Point of Interconnection verified that there were no actual drops in Real Power from the facility at the time.

Solar Facility in Central Texas with 500 MW nameplate rating:
The DT analyzed one month of data for June 2024 and found seven events in which the facility changed 50 MW or more within a four second period, the first four of these events appear to be caused by curtailment issues. The plant was either being curtailed or was released from curtailment at the time which four of the seven events were detected. One of those events showed a large increase of irradiance at the time, but it is unclear if the change of irradiance alone caused the sudden increase in generation or if it was due to improper curtailment ramp rates, or a combination of the two. Two of the other events were related to large oscillations lasting up to an hour in which peak to peak magnitude of the oscillation exceeded 50 MW. The last event was due to a Power Plant Controller issue that caused a sudden drop in Real Power of 246 MW and was previously identified by the Reliability Coordinator. Under Requirement R1 requirements, three of the seven events would meet criteria and need to be analyzed in Requirement R2. The table below summarizes the results:

Date/Time	Four second MW change	Increase/ Decrease	Significant Irradiance Change	Cause	Should be Analyzed in R2
6/4/2024 1:25:00 PM	83	Increase	Yes	Curtailment issue/ Irradiance change?	No (Resource dispatch and/or change in irradiance exclusion)
6/4/2024 5:00:00 PM	192	Increase	No	Curtailment released	No (Resource dispatch exclusion)
6/14/2024 8:02:00 AM	57	Increase	No	Curtailment issue	No (Resource dispatch exclusion)
6/14/2024 11:36:00 AM	138	Increase	No	Curtailment issue	No (Resource dispatch exclusion)
6/17/2024 11:45:00 AM	246	Decrease	No	Plant controller issue	Yes
6/23/2024 12:30:00 PM	50	Both	No	Oscillation Event	Yes (peak to peak magnitude >50 MW observed)
6/26/2024 4:00:00 PM	78	Both	No	Oscillation Event	Yes (peak to peak magnitude >50 MW observed)

The DT also analyzed data covering one month from four facilities in Hawaii and found only one event that exceeded thresholds in Requirement R1. Since facilities in this area are generally smaller, all four facilities

analyzed were less than 200 MW in nameplate rating, so a 20 MW threshold was used for analysis. The DT also looked at an extended time period of 60 seconds, and as expected, more events were identified with the extended time period.

Plant #	1	2	3	4
Technology	Wind	PV	PV/BESS (AC Couple)	BESS Standalone
Facility Nameplate Rating (MW)	69	46	39	135
# of event (4 second, >20 MW)	0	0	0	1 (cause unknown)
# of event (60 second, >20 MW)	0	0	0	8

Due to the above analysis, the DT believes the thresholds in Requirement R1 would rarely trigger events due to normal operation of an IBR facility if the facility is operating as expected. The DT only found one possible instance of a facility exceeding the thresholds due to change of irradiance and wind speed, and it was likely caused by improper curtailment ramp rates programmed into the Power Plant Controller. In addition, the DT reviewed papers published by NREL on Solar PV Variability at Small Timescales and Variability of Wind Power Output, which concludes that change in irradiance and wind speed would not have large impacts to changes in output within a narrow timeframe such as a four second period.

The intention of the four second period was to specify what constitutes a sudden change in power, similar to the types of Real Power loss events described in NERC Disturbance Event reports. The DT considered using the term “scan period” to define the change period, because this scan period is the basis of the time, but chose to stay with the four second time specification. Four seconds is a common industry practice, MISO’s scan rate, which is one of the longest, has a time duration of four seconds. The four second threshold is meant to provide a significant exclusion because the change must occur quickly, within that time. Increasing the time effectively reduces the rate of change and would identify more events than a four second window. The intent is to exclude from review slow power changes expected with normal operations (e.g., variable output from weather, dispatch, planned outages, testing) or expected responses (e.g., loss of interconnection facilities), which were defined as bullet points to Requirement R1.

The standard four second time only applies to the period of calculating the Real Power change, such as a sudden drop, to be considered valid events identified under Requirement R1. This time does not limit or imply any duration for the entire event. While the change must occur within the four second timeframe, the plant response may take tens of seconds or even minutes. The standard does specify or limit that time period.

The term “changes in Real Power” encompasses both sudden decreases (i.e., loss of output) and increases (i.e., additional consumption) that may be caused by IBR mis-operations that could affect system

reliability. For instance, a battery energy storage system that mis-measures system frequency may unexpectedly enter a charging mode and suddenly increase Real Power draw.

Photovoltaic (PV) example 1 – qualifying:
PV facility with gross nameplate rating of 220 MW is operating with active output of 80 MW. During a transmission system fault event,[2] the plant exhibits a near instantaneous Real Power output drop to 50 MW.

The change in apparent power in under four seconds is 30 MW, which exceeds 22 MW, the greater of 10% of the plant's gross nameplate (22 MW) or 20 MW. This IBR performance event is required to be captured by the GO's process implemented in Requirement R1.

PV example 2 – non-qualifying:
PV facility with gross nameplate rating of 80 MW is operating with active output of 60 MW. During a transmission line fault event,[1] the plant exhibits a near instantaneous Real Power output drop to 42 MW.

The change in apparent power in under four seconds is 18 MW, <u>not</u> exceeding 20 MW, the greater of 10% of the plant's gross nameplate rating (8 MW) or 20 MW. This IBR performance event is <u>not</u> required to be captured by the GO's Requirement R1 process.

Battery Energy Storage System (BESS) example 1 – qualifying:
BESS facility with gross nameplate power output rating of 80 MW is operating as a load drawing 50 MW. During a power plant controller (PPC) malfunction event of the BESS facility, the PPC incorrectly estimates system frequency sending an incorrect frequency response signal causing the plant to exhibit a near instantaneous change in real power to 10 MW injection.

The change in apparent power in under four seconds is 60 MW, which exceeds 20 MW, the greater of 10% of the BESS gross nameplate (8 MW) or 20 MW.
This IBR performance event is required to be captured by the GO's Requirement R1 process.

BESS example 2 – non-qualifying:
BESS facility with gross nameplate power output rating of 80 MW is outputting 40 MW. The BESS facility is curtailed by the Reliability Coordinator such that the plant exhibits a near instantaneous Real Power decrease to 15 MW.

The change in apparent power in under four seconds is 25 MW, exceeding 20 MW, the greater of 10% of the plant's gross nameplate rating (8 MW) or 20 MW. However, the change in apparent power is the result of the Reliability Coordinator curtailment which is an exempt event per Requirement R1. This IBR performance event is <u>not</u> required to be captured by the GO's Requirement R1 process.

[2] The transmission line fault is assumed not to be on the line connecting the IBR to the system, but rather is a fault remote from the IBR.

Rationale for Requirement R2

Requirement R2 requires analysis of events that meet Requirement R1 thresholds. Requirement R2 also provides an alternative path of event identification by the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operators (TOP). It is anticipated that some events would only be detected by one entity, but the combination of both identification methods would better identify events potentially posing reliability challenges.

Requirement R2 allows 90 days to analyze expected versus actual IBR responses to place an emphasis on diligent resolution, while still allowing enough time to conduct an analysis and identify causes. Ninety days allows adequate time for GO to interact with manufacturers and examine capabilities of equipment. In establishing this timeframe, the DT considered the PRC-004 timeline of 120 days, recognizing important differences between the application of these standards. PRC-004-4(i) Technical Rationale states "The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed".[3] The PRC-004 timeframe accounts for extreme weather events such as hurricanes that may affect a very large number of Protection Systems for a given responsible entity. The volume of IBR exposed to potential expected operation is anticipated to be lower when compared to Protection Systems and therefore a shorter timeframe is appropriate for PRC-030. The 90-day period starts from the event date for GO-identified performance issues resulting from Requirement R1 or upon request from the Balancing Authority, Reliability Coordinator, or Transmission Operator regarding IBR responses identified during system events.

Requirement R2, Part 2.1 includes subparts to analyze performance during a Real power change event. Requirement R2, Part 2.1.1 requires identification of the root cause. Requirement R2, Part 2.1.2 requires that the facility's Ride-through performance including reactive power response is documented (Requirement R2, Part2.1.2). Requirement R2, Part 2.1.3 requires that the GO assess the performance issue(s) and determine whether corrective actions are needed. Requirement R2, Part 2.1.4 requires that the GO consider the applicability of the root cause to its other IBR facilities. Collectively, the subparts define the minimum features required as part of an effective analysis. Requirement R2, Part 2.2 closes the communication loop with Balancing Authority, Reliability Coordinator, and Transmission Operator entities, should these entities request analysis results.

When the root cause cannot be identified or a root cause is identified but the GO cannot fully mitigate it, then it is expected the GO will continue to work with the associated reliability entities and Original Equipment Manufacturers to follow up on such instances and deploy mitigation plans when these become available. The GO will continue to coordinate with associated reliability entities through improvements to root cause analysis and CAPs until such a time the mitigation plans are in place. Such improvements include better data capture, and fault logging capabilities for subsequent future events.

[3] Standard PRC-004-4(i) – Protection System Misoperation Identification and Correction. Available at: https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-004-4(i).pdf

Rationale for Requirement R3

Should Requirement R2 determine a need for corrective actions, Requirement R3 requires a CAP or technical justification be developed within 60 calendar days of completing the analysis in Requirement R2, as identified in Requirement R2, Part 2.1.3. If Requirement R2 did not identify the need for corrective actions, then no action is required under Requirement R3.

Resolving the causes of IBR performance issues benefits BPS reliability by preventing recurrence. The CAP is an established tool for resolving operational problems. The NERC *Glossary* defines a Corrective Action Plan as, "A list of actions and an associated timetable for implementation to remedy a specific problem." Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the IBR Performance issue cause(s) is identified in Requirement R2 or Requirement R3 requires Generator Owner(s) to develop a CAP or provide a technical justification that addresses why corrective actions will not be applied nor implemented. The CAP is provided to the Reliability Coordinator, Balancing Authority, and Transmission Operator so that these entities 1) gain information potentially relevant to recent system events, and 2) can account for potential IBR performance issues in operational risk assessments.

This standard recognizes there may be multiple causes for IBR performance issues. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a CAP to correct multiple causes of an IBR performance issue. The 60-calendar day period for developing a CAP or technical justification is established based on industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent IBR performance issues from reoccurring, the timetable for executing such actions, and an evaluation of the CAP's applicability to the GO's other IBR including those at other locations. The evaluation of these other IBR with similar designs aims to reduce the risk and the likelihood of similar IBR performance issues in other IBRs. The GO is responsible for determining the extent of its evaluation concerning other IBRs and locations. The evaluation may result in the GO including actions to address IBR at other locations or to provide a technical justification that addresses why corrective actions will not be applied nor implemented.

Acceptable technical justification for not performing corrective actions is expected to primarily have two characteristics:
1) interconnection requirements on IBR performance extending beyond those in place at the time of interconnection; and
2) it would require significant material modifications/qualified change.

Technical justifications for not performing corrective actions do not relieve the GO from compliance with other standards (i.e., PRC-029-1 Ride-Through) to the extent that other standards are applicable.

Rationale for Requirement R4

Requirement R4 requires that each applicable GO implement the CAP developed in Requirement R3, as applicable, to mitigate deficiencies identified in Requirement R2. In the NERC *Glossary*, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem."

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. If the CAP is changed, the entity must notify the applicable Reliability Coordinator(s)~~, Transmission Operator(s), or Balancing Authority (s)~~. The entity must also notify applicable RC(s) when the CAP has been completed. The implementation of a properly developed CAP ensures that causes of unexpected changes in IBR power output are mitigated in a timely manner.

An IBR deficiency may require the Reliability Coordinator to impose operating restrictions so the system can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions should incentivize the entity to complete the CAP as quickly as possible.

Violation Risk Factor and Violation Severity Level Justifications

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

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 Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues. 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 Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric 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 Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric 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 Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric 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 Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric 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 Electric System, or the ability to effectively monitor and control the Bulk Electric 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 Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric 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-030-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because not having a process for identifying changes in Real Power output, which is required in defining the minimum standards will be performed, could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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 medium 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-030-1, Requirement R1	
Proposed VRF	**Medium**
than One Obligation	

VSLs for PRC-030-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity failed to implement a documented process to identify changes in Real Power output in accordance with Requirement R1.

VSL Justifications for PRC-030-1, 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.
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-030-1, Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because a Generator Owner not analyzing it's Inverter Based Resource's performance which are required in defining the minimum standards will be within 90 days of an event, identified pursuant to Requirement R1 or receipt of a request pursuant to Requirement R2, to address the unexpected change(s) in power output and the applicability to its other IBR facilities that could be affected by the same cause of unexpected change(s) in power output could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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	This VRF is in line with the definition of a medium VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-030-1, Requirement R2	
Proposed VRF	**Medium**
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-030-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed an analysis in accordance with Requirement R2, but in more than 90 calendar days but less than 120 calendar days of an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 120 or more calendar days but less than 150 calendar days of an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 150 or more calendar days but less than 180 calendar days of an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 or Part 2.1.4. OR The responsible entity failed to provide the analysis results from the requesting entity in accordance with Requirement R2, Part 2.2.	The responsible entity developed an analysis in accordance with Requirement R2, but in 180 calendar days or more of an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 and Part 2.1.4. OR The responsible entity failed to document the facility's Ride-through performance in accordance with Requirement R2, Part 2.1.2 OR

			The responsible entity failed to determine the applicability of other Inverter-Based Resource facilities in accordance with Requirement R2, Part 2.1.4.

VSL Justifications for PRC-030-1, 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 Ambiguous Language	The proposed VSLs are not 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	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for PRC-030-1, Requirement R2	
Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF Justifications for PRC-030-1, Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because a Generator Owner's failure to develop either a Corrective Action Plan (CAP), or technical justification that addresses why corrective actions will not be applied nor implemented for it's Inverter Based Resource's could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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 medium VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-030-1, Requirement R3	
Proposed VRF	**Medium**
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-030-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 60 calendar days, but provided it within 90 calendar days.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 90 calendar days, but provided it within 120 calendar days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 120 calendar days, but provided it within 150 calendar days OR The developed CAP did not include corrective actions for other facilities owned by the Generator Owners as identified in Requirement R2 Part 2.1.3, if necessary. OR The developed CAP or technical justification was not provided to the associated Reliability	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented, within 150 calendar days.

		Coordinator, Balancing Authority, and Transmission Operator.	

VSL Justifications for PRC-030-1, 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 not 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-030-1, Requirement R3	
Number of Violations	

VRF Justifications for PRC-030-1, Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because failure to implement, update, or notify with the applicable Reliability Coordinator (RC) the Corrective Action Plan (CAP) for it's Inverter Based Resource's could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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 medium 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-030-1, Requirement R4	
Proposed VRF	**Medium**
than One Obligation	

VSLs for PRC-030-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R4.

VSL Justifications for PRC-030-1, 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	The proposed VSLs are not 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-030-1, 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.

Violation Risk Factor and Violation Severity Level Justifications

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

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 Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues. 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 Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric 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 Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric 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 Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric 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 Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric 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 Electric System, or the ability to effectively monitor and control the Bulk Electric 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 Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric 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-030-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because not having a process for identifying changes in Real Power output, which is required in defining the minimum standards will be performed, could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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 medium 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-030-1, Requirement R1	
Proposed VRF	**Medium**
than One Obligation	

VSLs for PRC-030-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity failed to implement a documented process to identify changes in Real Power output in accordance with Requirement R1.

VSL Justifications for PRC-030-1, 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.
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-030-1, Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because a Generator Owner not analyzing it's Inverter Based Resource's performance which are required in defining the minimum standards will be within 90 days of an event, identified pursuant to Requirement R1 or receipt of a request pursuant to Requirement R2, to address the unexpected change(s) in power output and the applicability to its other IBR facilities that could be affected by the same cause of unexpected change(s) in power output could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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	This VRF is in line with the definition of a medium VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-030-1, Requirement R2	
Proposed VRF	**Medium**
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-030-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed an analysis in accordance with Requirement R2, but in more than 90 calendar days but less than 120 calendar days of an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 120 or more calendar days but less than 150 calendar days of an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R2, but in 150 or more calendar days but less than 180 calendar days of an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 or Part 2.1.4. OR The responsible entity failed to provide the analysis results from the requesting entity in accordance with Requirement R2, Part 2.2.	The responsible entity developed an analysis in accordance with Requirement R2, but in 180 calendar days or more of an event or receiving a request. OR The responsible entity performed the analysis in Requirement R2 but failed to address Part 2.1.1 and Part 2.1.4. OR The responsible entity failed to document the facility's Ride-through performance in accordance with Requirement R2, Part 2.1.2 OR

			The responsible entity failed to determine the applicability ~~susceptibility~~ of other I~~i~~nverter-B~~b~~ased R~~r~~esource facilities in accordance with Requirement R2, Part 2.1.4~~3~~.

VSL Justifications for PRC-030-1, 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 Ambiguous Language	The proposed VSLs are not 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-030-1, Requirement R2	
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-030-1, Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because a Generator Owner's failure to develop either a Corrective Action Plan (CAP), or technical justification that addresses why corrective actions will not be applied nor implemented for it's Inverter Based Resource's could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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	This VRF is in line with the definition of a medium VRF requirement per the criteria filed with FERC as part of the

VRF Justifications for PRC-030-1, Requirement R3	
Proposed VRF	**Medium**
Guideline 4- Consistency with NERC Definitions of VRFs	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-030-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 60 calendar days, but provided it within 90 calendar days.	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented within 90 calendar days, but provided it within 120 calendar days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 120 calendar days, but provided it within 150 calendar days OR The developed CAP did not include corrective actions for other facilities owned by the Generator Owners as identified in Requirement R2 Part 2.1.3, if necessary. OR The developed CAP or technical	The responsible entity failed to develop a CAP or provide a technical justification addressing why no corrective actions will be implemented, within 150 calendar days.

		justification was not provided to the associated Reliability Coordinator, Balancing Authority, and Transmission Operator.	

VSL Justifications for PRC-030-1, 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 not 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	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for PRC-030-1, Requirement R3	
Violation, Not on A Cumulative Number of Violations	

VRF Justifications for PRC-030-1, Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate because failure to implement, update, or notify with the applicable Reliability Coordinator (RC) the Corrective Action Plan (CAP) for it's Inverter Based Resource's could directly affect the electrical state or the capability of the Bulk-Electric System (BES), or the ability to effectively monitor and control the BES. In addition, a violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore, it is in line with the definition of a Medium VRF.
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 Medium 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 medium VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of	This requirement does not co-mingle a higher risk reliability objective and a lesser risk reliability objective.

VRF Justifications for PRC-030-1, Requirement R4	
Proposed VRF	**Medium**
Requirements that Co-mingle More than One Obligation	

VSLs for PRC-030-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R4.

VSL Justifications for PRC-030-1, 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	The proposed VSLs are not 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-030-1, Requirement R4	
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.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

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

Final Ballot Open through September 27, 2024

Now Available

A final ballot for **PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation** is open through **8 p.m. Eastern, Friday, September 27, 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*.

To assist industry in this upcoming 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.

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 Standards Developer, Josh Blume (via email) or at 470-755-0346.

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

Ballot Results

Ballot Name: 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues PRC-030-1 FN 5 ST
Voting Start Date: 9/23/2024 9:40:08 AM
Voting End Date: 9/27/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 5
Total # Votes: 251
Total Ballot Pool: 277
Quorum: 90.61
Quorum Established Date: 9/23/2024 10:09:16 AM
Weighted Segment Value: 70.88

Actions

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	76	1	39	0.722	15	0.278	0	16	6
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	60	1	33	0.647	18	0.353	0	6	3
Segment: 4	13	1	5	0.5	5	0.5	0	2	1
Segment: 5	69	1	31	0.62	19	0.38	0	8	11
Segment: 6	44	1	22	0.647	12	0.353	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: 10	7	0.6	6	0.6	0	0	0	0	1
Totals:	277	6.4	144	4.536	69	1.864	0	38	26

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
6	Entergy	Julie Hall		Negative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	N/A
1	Black Hills Corporation	Travis Grablander		Negative	N/A
6	Portland General Electric Co.	Stefanie Burke		Abstain	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A

5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
6	AEP	Mathew Miller		Abstain	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
5	American Municipal Power	Amy Ritts		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Negative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A

4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Negative	N/A
4	DTE Energy	Patricia Ireland		Negative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Abstain	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
6	Manitoba Hydro	Brandin Stoesz		Affirmative	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	None	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		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
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Negative	N/A
			Denise		

3	Imperial Irrigation District	George Kirschner	Sanchez	Affirmative	N/A
6	Great River Energy	Brian Meloy		Affirmative	N/A
1	Entergy	Brian Lindsey		Negative	N/A
5	NextEra Energy	Richard Vendetti		Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	Constellation	Alison MacKellar		Negative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		None	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
1	Eversource Energy	Joshua London		Abstain	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
3	Entergy	James Keele		Negative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
1	Duke Energy	Katherine Street	Ellese Murphy	Affirmative	N/A
3	Omaha Public Power District	David Heins		Negative	N/A
6	Invenergy LLC	Colin Chilcoat		Negative	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
6	Muscatine Power and Water	Nicholas Burns		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A

5	Muscatine Power and Water	Chance Back		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		None	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Negative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A
6	Constellation	Kimberly Turco		Negative	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Negative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A

3	Austin Energy	Lovita Griffin		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	N/A
4	Austin Energy	Tony Hua		Abstain	N/A
5	Austin Energy	Michael Dillard		None	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
5	Tennessee Valley Authority	Darren Boehm		Negative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	N/A
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		None	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		None	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	N/A
5	Enel Green Power	Natalie Johnson		Abstain	N/A

6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		Negative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	George Pino		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Negative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		None	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		None	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	N/A
1	JEA	Joseph McClung		Negative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Leo Bernier		Negative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	N/A
5	Pattern Operators LP	George E Brown		Negative	N/A
5	JEA	John Babik		None	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Negative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A

1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund	Negative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson	Negative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas	Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber	Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang	Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos	Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu	Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer	None	N/A

NERC Balloting Tool

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Ballot Results

Ballot Name: 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Implementation Plan FN 5 OT
Voting Start Date: 9/23/2024 9:41:09 AM
Voting End Date: 9/27/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: FN
Ballot Series: 5
Total # Votes: 252
Total Ballot Pool: 278
Quorum: 90.65
Quorum Established Date: 9/23/2024 10:09:19 AM
Weighted Segment Value: 74.78

Actions

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	76	1	41	0.759	13	0.241	0	16	6
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	60	1	35	0.686	16	0.314	0	6	3
Segment: 4	13	1	6	0.6	4	0.4	0	2	1
Segment: 5	70	1	33	0.66	17	0.34	0	9	11
Segment: 6	44	1	24	0.706	10	0.294	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: 10	7	0.5	5	0.5	0	0	0	1	1
Totals:	278	6.3	152	4.711	60	1.589	0	40	26

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
6	Entergy	Julie Hall		Negative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	N/A
1	Black Hills Corporation	Travis Grablander		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		Abstain	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A

3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
6	AEP	Mathew Miller		Abstain	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
5	American Municipal Power	Amy Ritts		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Negative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	N/A

5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Negative	N/A
4	DTE Energy	Patricia Ireland		Negative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Abstain	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
6	Manitoba Hydro	Brandin Stoesz		Affirmative	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	None	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
3	New York Power Authority	Richard Machado		Negative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Negative	N/A
			Denise		

3	Imperial Irrigation District	George Kirschner	Sanchez	Affirmative	N/A
6	Great River Energy	Brian Meloy		Affirmative	N/A
1	Entergy	Brian Lindsey		Negative	N/A
5	NextEra Energy	Richard Vendetti		Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	Constellation	Alison MacKellar		Negative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		None	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	N/A
1	Eversource Energy	Joshua London		Abstain	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
3	Entergy	James Keele		Negative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
1	New York Power Authority	Daniel Valle		Negative	N/A
1	Duke Energy	Katherine Street	Ellese Murphy	Affirmative	N/A
3	Omaha Public Power District	David Heins		Negative	N/A
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
6	Muscatine Power and Water	Nicholas Burns		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A

5	Muscatine Power and Water	Chance Back		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		None	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A

3	Austin Energy	Lovita Griffin		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
4	Austin Energy	Tony Hua		Abstain	N/A
5	Austin Energy	Michael Dillard		None	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
5	Tennessee Valley Authority	Darren Boehm		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	N/A
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		None	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		None	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	N/A
5	Enel Green Power	Natalie Johnson		Negative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A

1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Negative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		Negative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	George Pino		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		None	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		None	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	N/A
1	JEA	Joseph McClung		Negative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Leo Bernier		Negative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	N/A
5	Pattern Operators LP	George E Brown		Negative	N/A
5	JEA	John Babik		None	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A

1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund	Negative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson	Negative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas	Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber	Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang	Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu	Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan	Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos	Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer	None	N/A

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Exhibit H

Standard Drafting Team Roster

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Drafting Team Roster

Project 2023-02 Performance of IBRs

	Name	Entity
Chair	Mark Gutzmann	Xcel Energy
Vice Chair	Biju Gopi	California ISO
Members	Patrick Dalton	Midwest Independent System Operator
	Mohamed Elnozahy	Independent Electricity System Operator of Ontario (IESO)
	Patrick Gravois	ERCOT
	Emily Greene	Electric Power Engineers
	Andy Hoke	NREL
	Anuradha Kariyawasam	Electranix Corporation
	Chester Li	Hydro One
	Tracy MacNicoll	Utility Services of Vermont
	David Marshall	Southern Company Services
	Dan Waugh	NextEra Energy
	Anthony Williams	Duke Energy
	Li Yu	Hawaiian Electric Company
PMOS Liaison	Claudine Fritz	Exelon Corp
NERC Staff	Josh Blume, Standards Developer	North American Electric Reliability Corporation
	Lauren Perotti, Counsel	North American Electric Reliability Corporation