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.

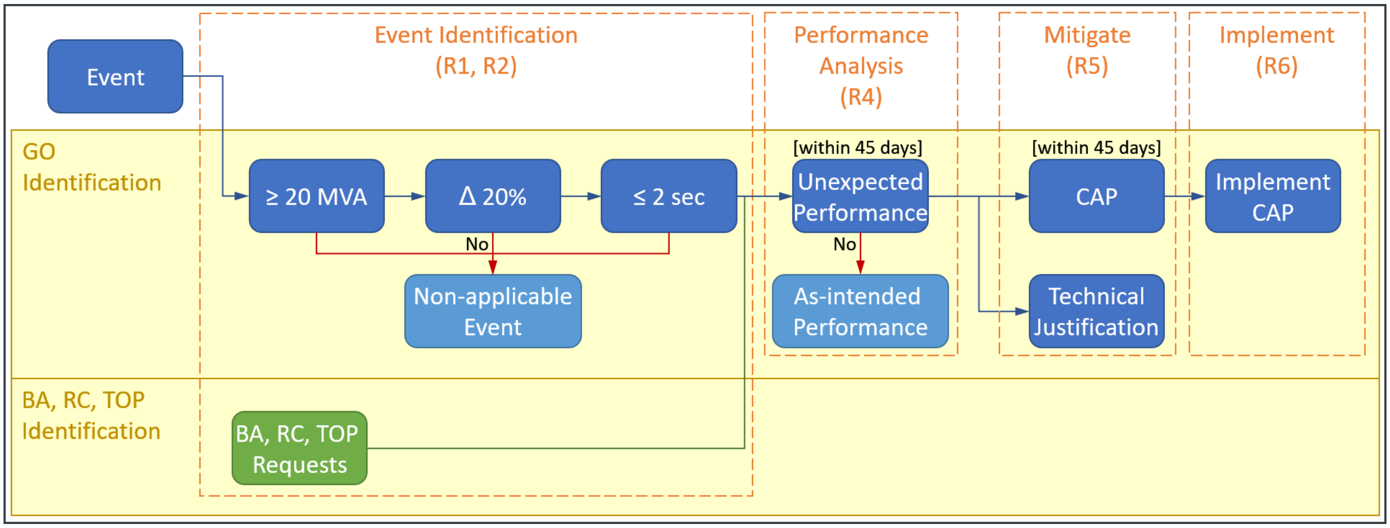

Figure 1.1: PRC-030-1 Flowchart

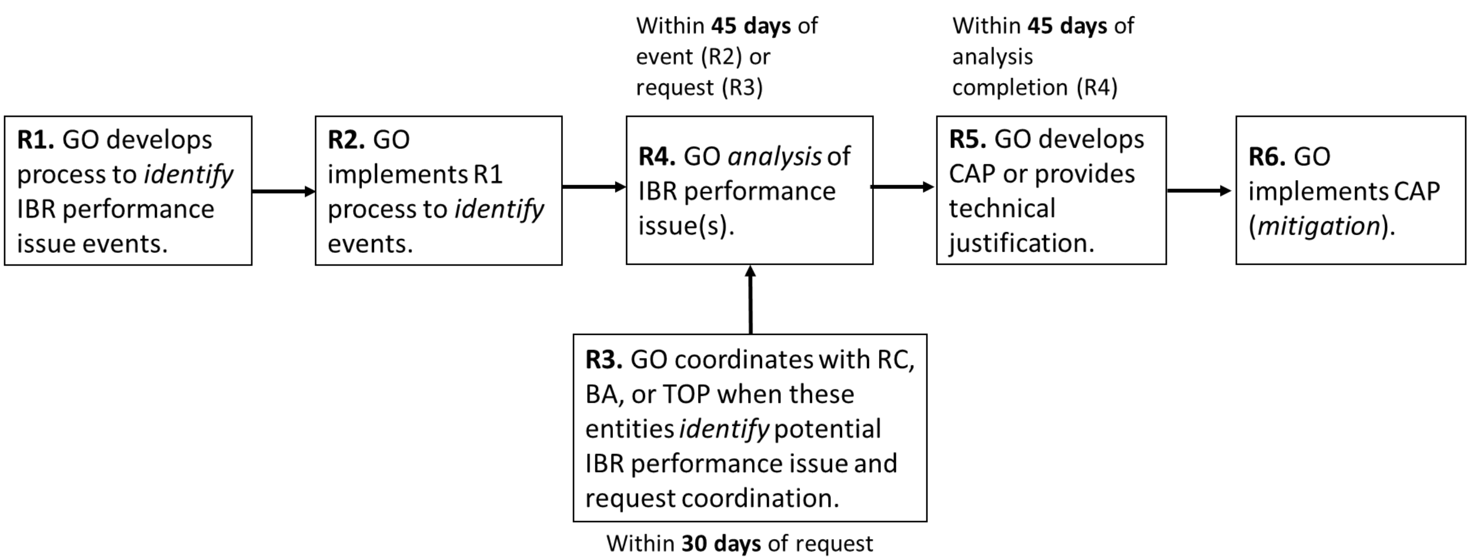

Figure 1.2: Relationship of PRC-030-1