

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 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
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 Proconiar	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
					Jarrold 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	
<p>WAPA isn't a GO, however we support the MRO NSRFs feedback:</p> <ul style="list-style-type: none"> • 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. <p>Alternative:</p> <ul style="list-style-type: none"> • 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	
<p>AZPS supports that following comments that were submitted by EEI on behalf of its members:</p> <p>EEI does not support the proposed language in Requirement R1 due to the following concerns:</p> <ol style="list-style-type: none"> 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	
<p>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.</p>	
Likes 0	
Dislikes 0	
Response	
<p>Thank you for the comment, this time frame refers to any time span.</p>	
<p>Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company</p>	
Answer	No
Document Name	
Comment	
<p>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.</p> <p>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.</p>	

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 MVA 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	
<ul style="list-style-type: none"> &bull; 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. &bull; The disturbance threshold should be described in MW, not MVA (20MW not 20 MVA). <ul style="list-style-type: none"> o Additional cost to calculate MVA that our controllers do not currently perform. &bull; 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. <ul style="list-style-type: none"> 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 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	
<p>BC Hydro appreciates the drafting team’s efforts and the opportunity to comment, and offers the following comments.</p> <p>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’?</p>	
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	
<p>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.</p> <p>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).</p>	

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. Most SCADA systems utilize a 2-second 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 doesn't 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 isn't 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 should 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	
<p>Thank you for the comment the DT response:</p> <ol style="list-style-type: none"> 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	
<p>Capital Power supports NAGF's comments.</p> <p><i>The NAGF does not support the proposed language for Requirement R1 and provides the following comments for consideration:</i></p> <p><i>a. The 2 second timeframe to identify unexpected changes in power output may not be possible for existing inverter-based resource (IBR) facilities.</i></p> <p><i>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.</i></p>	

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
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Dislikes	0
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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
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Document Name	
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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
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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	
<p>Yes. As currently defined in footnote 1, “unexpected changes” appears to include BPS events that an IBR responds to <i>correctly</i>. 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.</p> <p>An example of a change to the “unexpected changes” footnote to address this aspect is detailed below:</p> <p>“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.”</p> <p>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</p>	

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	
<p>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.</p>	
Likes	0
Dislikes	0
Response	
<p>The DT's response:</p> <ol style="list-style-type: none"> 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	
<p>The MRO NSRF provides the following feedback:</p> <ul style="list-style-type: none"> • 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	
<p>The DT’s response:</p> <p>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</p>	

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 Elhousseini - 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 do not fit into the listed exclusions and require further analysis.

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	Yes
Document Name	
Comment	
<p>AEPC signed on to ACES comments:</p> <p>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.</p> <p>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.</p> <p>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:</p> <p>“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.”</p> <p>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:</p> <ul style="list-style-type: none"> • 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; Fong 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 Telemetry 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 - Allele - 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	
<p>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.</p> <p>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.</p>	
Likes	0
Dislikes	0
Response	
<p>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.</p>	
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
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Document Name	
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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	
<p>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.</p> <p>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.</p> <p>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:</p>	

“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 four 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	
<p>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.</p>	
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; Fong 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	
<p>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.</p>	
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 - Allele - 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	
<i>Please reference all the NAGF comments provided on this comment form for possible cost-efficiencies.</i>	
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	
<p>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.</p>	
Likes	0
Dislikes	0
Response	
<p>Please see MRO response.</p>	
<p>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</p>	
Answer	Yes
Document Name	
Comment	
<p>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</p>	
Likes	0
Dislikes	0
Response	
<p>Thank you for the comment, please refer to the responses to NAGF and MRO NSRF.</p>	
<p>Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott</p>	
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:	
<p>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.</p>	
Likes 0	

Dislikes	0
Response	
Thank you for the comment.	
Michael Goggin - Grid Strategies LLC - 5	
Answer	Yes
Document Name	
Comment	
<p>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.</p> <p>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.</p> <p>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.</p>	
Likes	0
Dislikes	0
Response	
Thank you for the comment.	
Patricia Ireland - DTE Energy - 4, Group Name DTE Energy	

Answer	Yes
Document Name	
Comment	
<p>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 generating units, not cost-effective compared to the benefit derived.</p> <p>We suggest incorporating into the standard a de minimus capacity rating excluding smaller generators from the scope of this standard.</p>	
Likes	0
Dislikes	0
Response	
Thank you for the comment.	
Mohamad Elhousseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
<p>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 de minimus capacity rating that excludes smaller contributors from the scope of this standard.</p>	
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, 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 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 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 AECl	
Answer	Yes
Document Name	
Comment	
AECl 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 applicable 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 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.

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, unknowing 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 alternatives 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	
<p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>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</p>	

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 Inverter-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 Inverter-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	
<p>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.</p> <p>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.</p> <p>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."</p>	
Likes 0	
Dislikes 0	
Response	
<p>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.</p> <p>In Section 4.2.1, BPS has been replaced by BES.</p>	
<p>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</p>	
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:	
<ol style="list-style-type: none"> Overall, ATC agrees that the standard is needed and is addressing an industry need. 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	
<p>R1: The language isn't clear enough. Our Wind SME interpreted it this way:</p>	

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 notification 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 Reliability 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 would be 120 days to conduct analysis and another 60 days to develop 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:	
<ol style="list-style-type: none"> 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	
<p>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</p> <p>Section 4. Applicability:</p> <p>4.1 Functional Entities: Generator Owner</p> <p>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.</p>	
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	
<p>Enel North America Inc. (Enel) has the following comments on Draft 1 of PRC-030-1:</p> <p>For Requirement R2, since Enel does not agree with Requirement R1 having a documented process, R2 should be removed.</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>Enel supports the comments made by the MRO NSRF regarding defining IBR prior to approval and implementation of PRC-030.</p>	
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 not 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	
<p>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.</p> <p>We are concerned that the standard refers to a defined term for IBR which has yet to be adopted in project 2020-06.</p> <p>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.”</p>	
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	
<p>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.</p> <p>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</p>	

(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 AECl

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.

Additionally, 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	
<p>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.</p> <p>Kimberly Turco on behalf of Constellation Segments 5 and 6</p>	
Likes 0	
Dislikes 0	
Response	
<p>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.</p>	
Mohamad Elhousseini - 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	
<p>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?</p> <p>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.</p> <p>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.</p>	
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	
<p>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.</p> <p>We are concerned that the standard refers to a defined term for IBR which has yet to be adopted in project 2020-06.</p> <p>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.”</p>	
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	
<p>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</p>	
Likes 0	
Dislikes 0	
Response	
<p>Thank you for the comment, please refer to the responses to EEI, NAGF, and MRO NSRF.</p>	
<p>Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company</p>	
Answer	
Document Name	
Comment	
<p>In the applicability section, the precise scope of IBRs needs to be clearly defined rather than stating "GOs with BPS IBRs".</p> <p>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.</p> <p>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.</p> <p>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</p>	

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; Fong 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	
<p>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).”</p> <p>This language is too broad and would include <i>all</i> IBRs interconnected to the Bulk Power System at <i>any</i> 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:</p> <p>“4.1. Functional Entities:</p> <p>4.1.1. Generator Owner <i>that owns equipment as identified in section 4.2</i> [emphasis added]</p> <p>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.”</p> <p>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.</p>	
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 not 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	
<p>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.</p> <p>EEI COMMENTS</p> <p>EEI offers the following additional edits to PRC-030-1:</p> <p>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):</p> <p>4.1. Facilities:</p> <p>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.</p>	

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 section indicates that this standard is limited to BPS Inverter-Based Resources. WECC interprets 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 - Allele - 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	
<p>EEI offers the following additional edits to PRC-030-1:</p> <p>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):</p> <p>4.1. Facilities:</p> <p>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.</p> <p>Requirements R2 through R6 Comments: EEI suggests the following changes to better align with other NERC Reliability Standards:</p> <p>Propose combining Requirement R2 with R1: See EEI’s justification within our response to question 1.</p> <p>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.</p> <p>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</p>	

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	
<ul style="list-style-type: none"> 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: <p>“The SAR should apply to all BES inverter-based resources.”</p> <p>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.</p> <ul style="list-style-type: none"> 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. <p>Thus, ACES recommends the following changes to Section 4:</p> <p>4.1 Functional Entities:</p> <p>4.1.1 Generator Owner (GO)</p> <p>4.2 Facilities:</p> <p>4.2.1 Inverter-Based Resource (IBR) meeting the registration criteria for either a Category 1 or Category 2 GO, with the following exclusions:</p> <p>4.2.1.1 Protection Systems</p> <p>4.2.1.2 Special Protection Systems (SPS)</p> <p>4.2.1.3 Remedial Action Schemes (RAS)</p> <p>4.2.1.4 Underfrequency Load Shedding (UFLS) that is intended to trip one or more BES Elements</p>	

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