Consideration of Comments

Project Name:	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues | Draft 2
Comment Period Start Date:	6/7/2024
Comment Period End Date:	7/10/2024
Associated Ballot(s):	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Implementation Plan AB 2 OT 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues PRC-030-1 AB 2 ST

There were 49 sets of responses, including comments from approximately 152 different people from approximately 101 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, contact Manager of Standards Information, Nasheema Santos (via email) or at (404) 446-2564.

Questions

1. Does the entity believe there should be any proposed changes in the thresholds in Requirement R1?

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

3. Does the entity have any concerns regarding the 2023-02 Implementation Plan? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

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

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO

					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	MRO,SPP RE,WECC	SRC 2024	Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	1	WECC
					Helen Lainis	IESO	1	NPCC

					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Greg Campoli	NYISO	1	NPCC
					Elizabeth Davis	PJM	2	RF
					Matt Goldberg	ISO New England	2	NPCC
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
Exelon	Daniel Gacek	1		Exelon	Daniel Gacek	Exelon	1	RF
					Kinte Whitehead	Exelon	3	RF
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF

					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
Black Hills Corporation	Rachel Schuldt	6			Micah Runner	Black Hills Corporation	1	WECC

				Black Hills Corporation - All Segments	Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated	1	NPCC

	Edison Co. of New York		
David Burke	Orange and Rockland	3	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
David Kwan	Ontario Power Generation	4	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
Sean Cavote	PSEG	4	NPCC
Jason Chandler	Con Edison	5	NPCC
Tracy MacNicoll	Utility Services	5	NPCC
Shivaz Chopra	New York Power Authority	6	NPCC

					Vijay Puran	New York State Department of Public Service	6	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
					Nicolas Turcotte	Hydro-Quebec (HQ)	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC
					Erin Wilson	NB Power	1	NPCC
					James Grant	NYISO	2	NPCC
					Michael Couchesne	ISO-NE	2	NPCC
					Kurtis Chong	IESO	2	NPCC
					Michele Pagano	Con Edison	4	NPCC
					Bendong Sun	Bruce Power	4	NPCC
					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
Dominion - Dominion	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion	3	NA - Not Applicable

Resources, Inc.						Resources, Inc.		
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC

					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Gary Dollins	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Olivia Olson	Sho-Me Power Electric Cooperative	1	SERC

					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	SERC
					Heath Henry	NW Electric Power Cooperative, Inc.	3	SERC
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	KAMO Electric Cooperative	1	SERC
					Brett Douglas	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Mark Riley	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC

					Chuck Booth	Associated Electric Cooperative, Inc.	5	SERC
					Jarrod Murdaugh	Sho-Me Power Electric Cooperative	3	SERC

1. Does the entity believe there should be any proposed changes in the thresholds in Requirement R1?

Kim Thomas – Duke Energy	
Answer	No
Document Name	(if an attachment is provided by submitter)
Comment	
None	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
Thank you for the comment.	

Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3

Answer	No
Document Name	
Comment	
SMEs responded with the following: “If this standard is enacted the threshold should be high to trigger events. There are too many variables to reliably screen out excluded events so a significant amount of time will be required just to determine if events should be analyzed.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment.	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	No
Document Name	
Comment	
If this standard is enacted the threshold should be high to trigger events. There are too many variables to reliably screen out excluded events so a significant amount of time will be required just to determine if events should be analyzed.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy has no issue with the proposed changes to the threshold in Requirement R1.	
Likes 0	
Dislikes 0	
Response	

Thank you for the support.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see the response to EEI's comment.	
Patricia Ireland - DTE Energy - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2024	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment.	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	

In reading the Technical Document in context with the question there seems to be some inconsistency. The Technical Document uses the terms “sudden changes in active power” and “unexpected”, however R1 has been edited to state “changes in active power output”. This can be interpreted to refer to “any changes inactive power output”. This is overly broad and can be misapplied. Further, the requirement refers to “Examples including changes in wind, solar irradiance”.

If R1 is deemed a valid requirement then the process should focus on early detection and notification/communication. Documented processes for equipment failures or predicted longer term weather events seems more practicable. Most importantly unexpected, unwarranted or unreliability performance should require a process to analyze the root cause and correct deficiencies.

The Drafting Team should focus on the stated purpose of the SAR:

“The scope of this project is to either create a new NERC reliability standard or modify an existing standard that requires IBRs that respond to grid disturbances in an unexpected, unwarranted, and unreliable manner to identify, analyze, and mitigate performance issues that occur within the facility. This includes any types of protections or controls that result in abnormal performance issues within the plant, including abnormal performance resulting in anomalous behavior of active power output from the facility during events.”

The wording of R1 does not support this statement of the scope of the project from the SAR. The Drafting Team should be more assertive in requiring GOs with IBRs to perform to a defined set of criteria to remain compliant. This includes full event analysis and root cause investigations where they violate performance criteria. Criteria can be softened so they do not have to perform perfectly 100% of the time, but there should be a threshold for performance.

Likes 0	
Dislikes 0	
Response	

Use of the terms sudden and unexpected led to much uncertainty and discussion as to how that would be applied consistently. Therefore, the DT chose to bound the initial change at event onset to a four second timeframe. Change is a broad term and that is why the DT set a minimum change threshold of 20 MW with a 10% change requirement as well. R2 address root cause in 2.1.1. This standard requires detection, analysis, and corrective actions for performance outside the Reliability Standards requirements. This standard does not set the requirements, but requires the plant compare its response to the requirements. Per NERC limitations, one standard cannot refer to other standards.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Dominion Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response to EEI's comment.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP supports the SDT's recommended threshold values in Requirement R1, however it is not explicitly stated in R1 where the measurement needs to be taken. AEP suggests adding the text "individually, at each MPT level" or some other defined point.	
Likes 0	
Dislikes 0	

Response	
It is the DT expectation that the change would be at the IEEE 2800 RPA. While that is typically the POM, it can be at other locations. At this point in the process, with limited time for review and comment, the DT did not make additional changes.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Our concern here is if there is a fault on the system there will be a momentary reduction in power output and it takes time (~ less than 500ms) for the output to return to steady state. Our main problem with the standard is all the burden is on the IBR GO, GOs would be required to evaluate "any" power loss event that is not excluded which is unnecessary in my opinion . Unless a facility fails to ride through a system disturbance then failures or issues at an individual site will probably not have much of an impact on the BES. Failures during ride through events should be evaluated.	
Likes 0	
Dislikes 0	
Response	
If the facility output changes and then returns to pre-even levels within 4 seconds (dip and return), then the standard considers that event, by default, to be expected behavior. While there could be some valid events to evaluate within this time period the standard does not currently require the GO to investigate these. The standard is, in part, looking for fast power changes with output changes that persist for many seconds.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

The requirement mandates "a documented process to identify changes in active power output that are the greater of 10% of the plant's gross nameplate rating or 20 MW." The BES definition's lower limit is 20 MVA. Therefore, assuming 100% PF, a unit at this lower limit would basically have to be totally lost in order for this requirement to come into play. On the flipside, take a 1,000 MVA plant - again, assuming 100% PF, it would have to lose (or gain) 100 MW for the requirement to be applicable. Is this the SDT's intent? If so, that's a pretty wide difference. If not, seems like the requirement's wording should be lower rather than greater.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the DT having a base floor of 20 MW, and 10% plants nameplate from that level on up.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation supports NAGF comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Please see the response to NAGF's comment.	
Alison MacKellar - Constellation - 5	
Answer	Yes

Document Name	
Comment	
Constellation supports NAGF comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Please see the response to NAGF's comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS supports the following comments that were submitted by EEI on behalf of its members: Comments: EEI appreciates the DT's efforts to set reasonable and workable thresholds for IBR GOs, however, we are concerned that photovoltaic (PV) plants could potentially be over burdensome administratively given the identified threshold for Real Power output changes of 10% of the plant's nameplate (or 20MW) over a 4 second period. While we understand why the DT chose the 4 second time period, we have no data to validate this is sufficiently narrow to avoid confusing changes in solar irradiance with a plants response to a system disturbance. We further note that for very large PV Plants, this threshold is likely sufficient, but we are concerned that smaller plants could be negatively impacted. To address this concern, we ask that the DT, NERC or one of the technical committees develop an investigation and written technical justification to support the proposed threshold and or consider consulting with NREL or EPRI to validate the veracity of the proposed threshold.	
Likes 0	

Dislikes 0	
Response	
Please see the response to EEI's comment.	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
R1. A 10% change in the active power output is too low and not the right metric. There are likely to be 10% changes that are not attributed to system disturbances which impact the plant operation, especially for wind or solar. The value should be raised back up to a 20% change. The cost of analyzing every 10% change is not commensurate with the benefit and does not focus on the intent of the SAR. The Standard should focus on the loss of individual generating units not on balance of plant protection systems.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the DT will consider this change. The team will also include reasoning in the Technical Rationale (TR) for coming up with these thresholds.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Avista agrees with the EEI Near Final Draft comments and concerns discussed in the draft comments.	
Likes 0	

Dislikes 0	
Response	
Please see the response to EEI’s comment.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
TEPC agrees with EEI's comments asking for a technical justification to support the proposed threshold.	
Likes 0	
Dislikes 0	
Response	
Please see the response to EEI’s comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Tri-State supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Please see the response to MRO’s comment.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
AES CE believes that the extension of the 2 second duration in R1 to 4 seconds will introduce a significant amount of new events requiring analysis and does not align with the Technical Rationale language that “The intent is to exclude from review slow power changes expected with normal operations”.	
Likes 0	
Dislikes 0	
Response	
The expectation of the DT is that GO will use SCADA to identify these events and perform the initial screening of expected events excluded by R1. Therefore, the DT does not want to make the time so short that more advanced monitoring capability is required. While extending the timeframe from two seconds to four seconds will include events that change marginally slower, the DT believes that changes over four seconds are still short enough to qualify as fast.	
Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Elevate appreciates the opportunity to comment on the draft NERC standards, particularly those pertaining to future IBR NERC Reliability Standards and FERC Order No. 901 directives. We support the goals of this standard to analyze and mitigate IBR performance issues; however, the standard as written would require significant analysis of events where IBR facilities respond to grid events *correctly*. This would not be cost effective and not aligned with	

the intention of the SAR as written. The major driver for this is the trigger criteria defined in Requirement R1. Requirement R1 defines the changes in active power output “occurring within a four-second period.” The “within four-second period” characterization may miss controller oscillations, control interactions, and slower active or reactive power responses in the wrong direction than intended. It would also pick up all types of dynamic events of an IBR facility, including events where an IBR facility performs correctly. This would lead to detailed forensic event analysis for almost every type of grid event rather than only those events where abnormal performance occurred.

Providing guidance in Requirement R1 for the trigger of the events of concern is a good practice but limiting the requirement language to specify only one trigger (e.g., the “changes in active power output occurring during a period that is no longer than 4 seconds”) to capture any type of unexpected changes with an IBR could result in certain types of events being missed while also capturing many events that don’t need to be analyzed (e.g., correct/intended responses of an IBR). The recommendation would be to include a set of event triggers as sub-requirements under Requirement R1.

Example triggers could include:

(1) ***Unexpected*** changes in active or reactive power output within a four-second period

(2) ***Unexpected*** changes in active or reactive power output ***longer*** than a four-second period, including momentary cessation, partial or full IBR tripping, or detailed recovery of active power response post-fault

(3) Active or reactive power oscillations that are poorly damped or persist for longer than *[consider value]* seconds

This structure would give the opportunity for additional triggers to be easily added and implemented/considered to more suitably capture unexpected operations occurring from IBRs on the BPS.

If additional trigger criteria are not used, another approach would be to modify the existing “within four-second window” criteria by adding additional SCADA scan rate samples into the existing trigger. Specifically, this would ensure that correctly performing dynamic events would ***not*** be considered within scope, and rather only significant power output changes that are sustained (i.e., trip of an IBR, active power output jump up/down that remains longer than a dynamic event such as momentary cessation or delayed power recovery, etc.). This would align with the language in the SAR to identify IBRs that incorrectly perform during dynamic grid events by either tripping, reducing active power, and not returning to pre-event output levels within 1-second.

Example criteria language for Requirement R1 along these lines could be:

"Changes in active power output that are the greater of either 10% of the plant's gross nameplate rating, or 20 MW, and the change in active power output remains at the new value for two or more consecutive SCADA scan rates [or could say remains at the new value for 2 seconds or longer]." In addition, the drafting team should consider modifying Requirement R1 and Requirement R2 so that changes in power output are not limited to just active power, but also reactive power. In fact, Requirement 2.1.2 highlights documentation a facility's ride-through performance including reactive power responses during grid events.	
Likes 0	
Dislikes 0	
Response	
At one point, the DT had statements very similar to those proposed. Use of the terms sudden and unexpected led to much uncertainty and discussion as to how that would be applied consistently. Therefore, the DT chose to bound the initial change at event onset to a 4 second timeframe. The 4 seconds is a limit on the amount of time within which the change is calculated, it is not the entire event timeframe. The 4 seconds is a guideline as to what a fast or sudden change is. It has no meaning or application to how long the event or response lasts in total. The DT recognizes that criteria to capture every type of event would require very complicated and detailed triggering specifications. The DT did not feel that was a practical objective, particularly given the time constraints for standard development. While the proposed criteria will certainly provide some false positives and miss some relevant events, the DT feels this criterion is balanced and adequate to detect the majority of events when the plant may have performed unexpectedly. While not specifically included, the DT expects that the enumerated evaluations would be performed as part of R2.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Yes, Black Hills Corporation feels changes are needed for Requirement 1. We are concerned for small photovoltaic (PV) plant could potentially be overburdened administratively given the identified threshold for Real Power output changes of 10% of the plant's nameplate (or 20 MW) over a 4 second period. We further note for very large PV plants, this threshold is likely sufficient. Black Hills Corporation requests clarification as to the basis/justification for the 4 second event threshold. Request the SDT Team to consider	

increasing the 4 second event threshold to capture only those Inverter-Based Resource (IBR) events that have a meaningful impact on the BPS.	
Likes 0	
Dislikes 0	
Response	
These Requirement R1 comments are addressed in previous comments on the topic.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
SMUD supports the comments submitted by AES Corporation.	
Likes 0	
Dislikes 0	
Response	
Please see the response to AES Corporation.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	

The NAGF requests clarification as to the basis/justification for the 4 second event threshold identified in Requirement R1. The NAGF requests the Drafting Team to consider increasing the 4 second event threshold to capture only those Inverter-Based Resource (IBR) events that have a meaningful impact on the BPS. In addition, the NAGF notes that the event identification and post-event performance validation process will largely be a manual labor-intensive process. Setting the right thresholds to only identify IBR events that have a meaningful impact to the BPS will help ensure optimal use of GO staff resources when identifying/analyzing such events.	
Likes 2	JEA, 1, McClung Joseph; Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
The recent industry events have a power change within a short timeframe and the DT believes the 4 seconds will identify meaningful events that have impact on BPS reliability.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power supports MRO’s NERC Standards Review Forum’s (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response to MRO NSRF’s comment.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	

Comment	
We agree with the EEI's comments and concerns discussed in their comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response to EEI's comment.	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Please see the response to EEI's comment.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Avista agrees with the EEI Near Final Draft comments and concerns discussed in the draft comments.	

Likes 0	
Dislikes 0	
Response	
Please see the response to EEI’s comment.	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI), North American Generator Forum (NAGF), and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 1	
Likes 0	
Dislikes 0	
Response	
Please see the responses to EEI’s, NAGF, and MRO NSRF’s comments.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
WECC believes the second draft is better developed but the risk is not being effectively mitigated. Leaning heavily on a GO analysis to develop a CAP OR provide a technical justification. And one of the "technical" justifications provided indicated the IBR was connected under old interconnection requirements (effectively grandfathering in everyone!). Also very concerned about the Implementation Plan	

that hinges on PRC-028 and PRC-029--Really need a complete diagram of the expectations of all 3 Standards (and the others associated with the Projects). PRC-028 is basically not completely effective until 2030.

There is not a defined term that matches “Transmission Provider”. Did the DT mean “Transmission Service Provider (TSP)”? As such, a TSP may not own any interconnection (e.g., ERCOT is the only TSP in the Texas Interconnection and has no interconnection facilities.) This needs to change to Transmission Owner(s) to be clear. WECC appreciates the DT’s approach to implementing a “documented” process. There are some discussions being held in the industry that mentioned removal of “documented” for compliance risk concerns. There is a bigger reliability risk without documented procedures to guide mitigation of the risks proposed by this Standard and others. It should be clear that R2 allows the RC, BA, or TOP to identify a Disturbance and a change in the inverter-based resource active OR reactive output and the GO should analyze the issue. This should not limit the RC/BA/TOPs to pursue IBR related events EVEN those not meeting the criteria for a GO to self-identify. Requirement R2.1 uses “IBR” versus “inverter-based resource” (as used in Requirement R2.1.4). It should be clear that if a RC, BA, or TOP provides a “request” trigger for actions a GO shall perform, per the base language in Requirement 2, there is not a need to “request” the output of the analysis in Requirement 2.2. Easily see an entity not retaining evidence to clearly demonstrate provision of the analysis indicating there was not a request for said analysis. Why would a RC, BA, or TOP simply request an analysis if the analysis would not be provided? The Technical Rationale indicates “some events would only be identified by one entity” while the Requirement is clear the GO must have a process to identify and the RC/BA/TOPs is limited in some respects under this Requirement. Suggest dropping “Upon request” at the start of Requirement R2.2. Setting the trigger off the gross nameplate value may mask significant events. The PV example 2 exhibits a 30% drop in Real-time output yet does not qualify. If other PV facilities are experiencing the same output level (75% of gross nameplate) because the time of day and an event occurs that drops 30% of all the inverter-based resources in the area, no self-analysis of the event is required. Consider changing the criteria to Real-time output to fully capture the risks. “Ride-through” should be listed as a term here with references to the Project proposing the definition (understand the Implementation Plan mentions approval of Prerequisite Standards.) There is no clarity in what “susceptibility” means in this context. The previous language regarding applicability should be retained. How will an entity demonstrate its determination of susceptibility? If an entity identifies NO performance issues and no corrective actions based on its analysis, how does that get communicated to the RC/BA/TOP? If the rigor of analysis dictates the path forward in the Standard (i.e. development/Implementation of a CAP) what incentives a GO to provide rigor in the analysis? Does the RC/BA/TOP have any mechanism to require corrective actions after a review of the analysis? Requirement R3 should use numbered bullets for consistency. The first bullet in Requirement R3 correctly addresses other applicable facilities but incorrectly identifies Requirement R2 Part 2.1.3 (Should be Requirement R2 2.1.4). Just to be clear, the developed CAP is to be provided to the applicable RC, BA, AND TOP (all three entities not just one), correct? Technical justifications should be limited to equipment limitations. CAPs could include changes in settings that were not initially recognized as a reliability risk but events have proved otherwise. Should add “(CAPs)” in Requirement R4 first sentence for consistency. Requirement R4 does not set any timeframes for expected completion of a CAP. An open-ended CAP does not appear to support reliability and the risk associated with IBR performance should be mitigated as quickly as possible. Also, notification of changes in the CAP or completion of the CAP is limited to the RC but should include the BA and TOP. Suggest "Notify the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator if CAP actions or timetables change and when the CAP is completed." Measure R4 would need the addition of BA and TOP as well. Measure M4 needs to reference "Requirement R4" not "Requirement R3" in the last sentence.

Likes 0	
Dislikes 0	

Response

"R3 requires submitting the CAP and technical justification to the RC. First, the DT expects the GO to consult subject matter experts who will apply sound engineering principles and use good engineering judgement in assessing the plant performance in comparison to the plant's performance requirements. The DT expects accountability to provide a solid technical justification to come from 1) repeated identification for improper performance, 2) review by the RC, and 3) audit for compliance to PRC-030.

The DT updated the Transmission Provider term.

The DT kept the documented process and agrees that it is an important element. The DT also agrees it is important to reinforce the RC may need to request performance reviews as well.

DT changed susceptibility to "applicability of the root cause to" to help clarify the context.

GOs will continue to communicate with the RC/BA/TOP through the currently established processes.

The standard is formatted based on NERC standards.

As the DT understands it, there is no precedent for CAP timeframes. Also, CAPs can be unique and require wide ranging timeframes for resolution. The DT team left establishing a timeline and monitoring the timeline to those entities that would currently be involved with reconciling transmission reliability issues and their current processes."

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	Yes
Document Name	
Comment	
The background information presented in this comment form aligns with the industry need outlined in the SAR.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI appreciates the DT's efforts to set reasonable and workable thresholds for IBR GOs, however, we are concerned that photovoltaic (PV) plants could potentially be over burden administratively given the identified threshold for Real Power output changes of 10% of the plant's nameplate (or 20MW) over a 4 second period. While we understand why the DT chose the 4 second time period, we have no data to validate this is sufficiently narrow to avoid confusing changes in solar irradiance with a plants response to a system disturbance. We further note that for very large PV Plants, this threshold is likely sufficient, but we are concerned that smaller plants could be negatively impacted. To address this concern, we ask that the DT, NERC or one of the technical committees to develop an investigation and written technical justification to support the proposed threshold and or consider consulting with NREL or EPRI to validate the veracity of the proposed threshold.	
Likes 0	
Dislikes 0	
Response	

The DT revised the wording to clarify that the DT intent is 20 MW and 10% change, not 20 MW or 10%. The 20 MW minimum change threshold causes the 10% change to only apply to 200 MW facilities and above. The 4 sec threshold is also meant to provide a significant exclusion because the change must occur quickly, within that time. Based on information available to the DT, wind and irradiance changes do not typically fit that time restraint.

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) does not support the 4 second reporting requirement in the proposed standard draft as that reporting occurrence wouldn't add value and could add unnecessary reporting constraints.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
The MRO NSRF does not believe that the proposed changes in the thresholds are sufficient. Requirement R1, as proposed, focuses on changes in active power output, less a few scenarios, which was not the intention of the SAR.	

Pursuant to the SAR (emphasis added), § Requested Information, ¶2, "IBRs to ensure that any unexpected ceasing of current injection (partial or full) is analyzed by the applicable Generator Owner and mitigated to the extent possible. NERC has also highlighted that many Generator Owners are not aware of these trips and that the Balancing Authority or Reliability Coordinator may often identify the unexpected or unwarranted tripping issues."

From the excerpt above it is clear that the proposed standard should focus on trips not caused by balance of plant (BOP) Protection Systems, but trips of the individual generating units. As such, the proposed Requirement R1 language needs to focus on generation resource capability, which is based on availability of individual generating units multiplied by the of individual generating unit's nameplate. For example, consider a wind generation resource with a 100MW aggregate gross nameplate that consists of 50 2MW individual generating units. When the wind generation resource is at 100% availability, then its capability would be 100MW, regardless of fuel supply. If the wind generation resource had 25 individual generating units' trip in a short period of time (≤ 1 minute), the new capability of the wind generation resource is now 50MW. The intention of the SAR was for Generator Owners to analyze these types of events (individual generating unit trips) to determine if performance issues exist, not any change in active power output.

It is not reasonable or practicable to have Generator Owners analyze every change in active power output even with the exclusions outlined in the proposed requirement. The MRO NSRF strongly encourages the SDT to consider the process that will be required to demonstrate compliance with the proposed Requirement R1 and the amount of administration that will be required to verify whether or not a change in active power meets the criteria for analysis in the Proposed Requirement R1.

The MRO NSRF believe that the that 10% change in the active power output is too low – there are likely to be 10% changes that are not attributed to system disturbances which impact the facility operation. It is suggested that this value be raised back up to 20% range of change.

An MRO NSRF member performed an analysis on one of their IBR facilities (100MW w/ 34 wind turbines) to determine the amount 10% or 20% changes in active power that occur from four-second to four-second or 60 second to 60 second time periods over a six-hour period, the results are as follows.

10% active power change

Total 4s Periods in a 6hr Period = 5400

Total PRC-030 Analysis's Required for a 6hr Period = 2250 or 41.667% (No Requirement R1 exclusions considered)

Please note that there were no 10% capability changes over this six-hour time period.

20% active power change

Total 60s Periods in a 6hr Period = 360

Total PRC-030 Analysis's Required for a 6hr Period = 150 or 41.667% (No Requirement R1 exclusions considered)

Please note that there were no 20% capability changes over this six-hour time period.

An additional concern the MRO NSRF has with the four second time frame is that BAL-005-1 R1 specifies a design scan rate of no more than six seconds for acquiring data necessary for calculating ACE and sending to the BA. That is really the defining time frame that is used to setup EMS systems to query BES RTU data. In addition, other entities could have longer scan rates up to 6 seconds. This is also dependent on the communications path and bandwidth available from EMS to the RTU. If a channel has multiple RTU connections on it, then the scan time can vary as it has to be tuned to be able to respond successfully given the bandwidth available to the multiple RTUs on the channel. The MRO NSRF believes that four seconds may be unachievable for some entities and it seems like the four second time should consider BAL-005-1 and an the amount active power changes that occur at an IBR. The MRO NSRF does not believe that amount of

precision can actually be achieved the way EMS systems are communicating with BA/RCs today unless some other monitoring mechanism is used. As such, the MRO NSRF suggest using a 20% change in capability over a one-minute time period to be the threshold for Requirement R1.	
Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
"The DT considers partial and full power reductions consistent with the SAR. Plants can have partial reductions due to full loss of individual units and plants can have partial reductions by having a proportional reduction across all units. The DT considers both to be partial reductions. The intention of using active power change rather just complete losses is to catch IBR plant performance issue defined in the SAR. The DT did not follow the example well enough to respond. Lengthening the timeframe to 60 seconds will produce more events to review rather than the current four seconds. During normal operations, the longer time windows allow for more change to occur. The standard only wants to identify fast changes. The standard 4 second time only applies to the period of calculating the power change, such as a sudden drop, to be considered valid events not the period of the entire event. A facility can implement the standard by capturing a single drop in telemetry if the scan rate is equal to or greater than four seconds, but a longer period could result in identifying more events than required by the standard. The standard is not intended to apply the four seconds or any scan rate to the entire event (event being the change itself, any pause before restoration, and the restoration of power)."	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	

As previously commented, WEC Energy Group does not agree with the 10% or 20 MVA threshold. The technical rationale states that “was chosen to be large enough to screen out normal operational events but not so large that it does not detect events that should be analyzed”. We do not agree that it is large enough to screen out normal events. The “unexpected changes” attributed to weather patterns, change of wind and/or change in irradiance factors occur on a daily basis in some geographical regions, often multiple times per day and can easily drop the site output by 10% or 20MVA. Therefore WEC Energy Group proposes that the threshold should be set to at least 75% of the site nameplate. WEC Energy Group agrees with the MRO NSRF comments/suggestion to merge R1 and R2.	
Likes 0	
Dislikes 0	
Response	
"20 MVA is a common cutoff for other Reliability Standards and the DT used that as a basis for this Standard. In this case, 20 MW is used rather than MVA. Because the 20 MW minimum change threshold causes the 10% change to only apply to 200 MW facilities and above. The 4 sec threshold is also meant to provide a significant exclusion because the change must occur quickly, within that time. Based on information available to the DT, wind and irradiance changes do not typically fit that time restraint. As a preventative measure to allowing smaller magnitude performance issues to persist until they also occur at a time when the power change is larger, the DT believes there is a benefit to reliability by detecting improper operation at lower levels of power change. "	
Douglas Darrah - Clearway Renewable Operation and Maintenance LLC - 5 - MRO,WECC,Texas RE,RF	
Answer	Yes
Document Name	
Comment	
Clearway Renewable Operation and Maintenance LLC (“Clearway”) supports the NAGF’s comments requesting clarification as to the technical basis for the 4 second event threshold and emphasizing the need to create a standard that optimizes GO staff resources.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment please see the response to MRO NSRF’s comment.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
AECI supports comments provided by the NAGF	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment please see the response to NAGF’s comment.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
To align with the SAR, the criteria for R1 should include 1.) Any complete facility trip/loss (regardless of the MW output at the time of the event) OR 2.) The ***lower*** of 10% of the plant’s ***gross MW output or input*** or 20 MW if the SDT continues with those thresholds. The 10% threshold may be considered reasonable for the majority of existing IBRs in operation; however future IBRs in the interconnection queue are rapidly growing in size. As of July 1, 2024, 744 new IBR projects in ERCOT will be greater than 200 MW. 85 of those will be greater than 500 MW and 7 of those greater than 1,000 MW. This means that reductions of greater than 100 MW for a 1,000 MW IBR plant could occur that would not be required to be analyzed. If a percentage threshold is still utilized in part of the criteria, it should be replaced with gross active power output (or input for storage). While solar sites may very well be closer to nameplate for several hours	

each day, wind resources are rarely beyond 60%-70% nameplate in ERCOT. Storage IBRs are even less often at nameplate. While ERCOT understands that the RC/BA/TOP may request disturbance data as well, it would be better to improve the criteria for R1 to minimize the need for such requests, allow greater self-monitoring to improve reliability, and minimize conflicts for such requests. ERCOT also recommends clarifying the first sentence to clarify that the active output level must equal or exceed the defined threshold value. Thus, the sentence should be revised to reference “changes in active power output **or input that equal or exceed** the **lower** of 10% of the plant’s gross **MW output or input** or 20 MW.” It is also unclear why the term “Transmission Provider” is being used. The SDT should review the standards or confer with NERC staff on the best functional entity or descriptor for the interconnection transmission provider. Perhaps “Transmission Owner” is the best term.	
Likes 0	
Dislikes 0	
Response	
The DT added a complete loss to R1. The DT also changed the wording of the two limits to 'and' to help clarify that both conditions must be met. The purpose of the two limits is to make the trigger points manageable for both large and small facilities. . The DT agrees that as the plant size grows, so does the trigger threshold, which is why the threshold was reduced from 20% to 10%. However, the DT ran out of time during this review cycle to consider what it thought might be somewhat complex changes to the criteria (the initial thought was to add a third criteria). The DT understands the need from the RC perspective and is one of the reasons the DT included the ability for the RC to request review, even when the 10% threshold is not met.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	

Ameren agrees with most of NAGF's comments, but with one difference. We believe the time period threshold in R1 of PRC-030 should align with PRC-029 if possible or provide a technical basis for choosing 4 seconds. For example, the present draft of PRC-029 dated 2024-03-27 shows a voltage ride-through requirement of 10 seconds for non-wind IBR and 1800 seconds for wind IBR which differs from the 4 second time as used in PRC-030. If the two standards are aligned, clarification should be made in PRC-030 or PRC-029 that if it is discovered that the IBR did not ride-through the expected time, it does not result in a violation of PRC-029 if the PRC-029 study was conducted prior to placing the plant in-service.	
Likes 0	
Dislikes 0	
Response	
The four second is for the initial power change is not related to times in PRC-029. Ride through is about the duration of the event. PRC-030 is triggering off a change over a four second period. PRC-030 only requires detection and evaluation of the event to comply. PRC-029 addresses the ride through performance itself. In that way, the DT believes the two standards are coordinated.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee’s comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see the response to NPCC’s comment.	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company believes that the 10% change in the active power output change is too low. Tthere are likely to be 10% changes that are not attributed to system disturbances which impact the plant operation. Southern Company suggests that this value be raised back up to a 15-20% change. Southern Compay also suggests that footnote 2 be included in the bullet of R1 to eliminate the footnote altogether. In the first sentence of Requirement R1, Southern Company suggests adding "MVA" before "nameplate rating". The intent is not to change any requirement but only to clarify how the required trigger point is determined.	
Likes 0	
Dislikes 0	
Response	
The DT revised the wording to clarify that the DT intent is 20 MW and 10% change, not 20 MW or 10%. The 20 MW minimum change threshold causes the 10% change to only apply to 200 MW facilities and above. Footnote two was moved. The DT understands the value and accuracy of using MVA but believes that will cause inconsistent application or questions about how to reconcile the active power changes with a MVA value.	
Michael Goggin - Grid Strategies LLC - 5	
Answer	Yes
Document Name	
Comment	

We are highly concerned that the updated standard reduced the threshold for output change events that must be reviewed to determine if they need to be analyzed. The revised standard sets the threshold at a change in output that is greater than 10% of the plant's nameplate rating (or 20 MW) within 4 seconds, relative to the previous threshold of 20% within 2 seconds. This change only adds to the generator owner's burden of manually reviewing each output change to exclude events caused by normal fluctuations in plant output due to weather, dispatch, and other factors. No mechanism exists for generator owners to automatically exclude those permissible changes from consideration. Wind and solar plants have a limited number of meteorological towers and pyranometers for measuring the available wind and solar resource, respectively, which makes it difficult in many cases to precisely determine whether changes in output across a plant were caused by resource availability. The new lower threshold will pick up many more such events, as changes of 10% output within 4 seconds routinely occur at solar and wind plants. As we explained in our previous comments, the passage of clouds over small to medium solar plants can cause changes in output of 75% of nameplate capacity per second.[1] As a result, in many cases the vast majority of events a generator owner is required to review will be these normal changes in output, diverting their time and resources away from addressing real reliability concerns. The drafting team's response to our prior comments only reinforces our concern about the burden imposed on the generator owner: "GOs would not know if it was unexpected behavior of generator settings and controls until the analysis is performed. The exceptions that have been moved from the footnote to the Standard Language allow for GOs to dismiss events due to cloud cover, change in wind speed. etc. Outage/Fault codes would be reviewed during the analysis process. It will be up to GOs to develop a process to identify events that that do not fit into the listed exclusions and require further analysis." It is highly burdensome for a generator owner to pull turbine- or inverter-level fault codes and plant-level fault codes for each event with a more than 10% change in output. Moreover, the drafting team cannot ignore the excessive and unworkable burden imposed on generator owners by simply dismissing that with "It will be up to GOs to develop a process to identify events that that do not fit into the listed exclusions and require further analysis." As explained in our answer to question 2 below, the best solution to these concerns may be to remove most if not all of R1, and instead rely on analysis requests initiated by the Reliability Coordinator, Balancing Authority, or Transmission Operator following a disturbance event that causes a drop in generator output per R2. {C}[1]{C} https://www.sciencedirect.com/science/article/abs/pii/S0306261917300144

Likes 0	
Dislikes 0	

Response	
The DT revised the wording to clarify that the DT intent is 20 MW and 10% change, not 20 MW or 10%. The 20 MW minimum change threshold causes the 10% change to only apply to 200 MW facilities and above. The 4 sec threshold is also meant to provide a significant exclusion because the change must occur quickly, within that time. Based on information available to the DT, wind and irradiance changes do not typically fit that time restraint. The link to the reference document did not provide the full document for review. DT members have reviewed operating data at a few plants and that analysis did not indicate an excessive number of events identified. Clarifying that the DT has always meant 20 MW to be a minimum threshold should reduce the number of potential events. The SAR requires that the GO to be primarily responsible for event detection.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
As drafted, the thresholds in Requirement R1 place a large burden on IBR GOs to analyze events where unexpected changes in active power output occur and events where IBRs respond correctly to System events. We believe this goes against the intent of the SAR, which is "to ensure that any **unexpected** ceasing of current injection (partial or full) is analyzed by the applicable Generator Owner and mitigated to the extent possible." In many cases, irradiance or wind speed data is not captured at such a high resolution from MET stations or it could be limited by data loggers in the field. The thresholds in R1 would result in significant work on the backend to isolate unexpected changes in active power output from changes associated with resource availability or even changes associated with an expected response to a System event. Consider utilizing SCADA scan rates rather than seconds in the threshold criteria.	
Likes 0	
Dislikes 0	
Response	
There is no specific way to define "unexpected" operation, and the use of that term caused considerable discussion about the definition. Rather than define unexpected, the DT noted clear cases of operational events that cause power changes (expected operation). While	

this may highlight the additional variables that impact the review, these variables must still be reviewed, even with a larger percentage, to classify partial reductions as unexpected. Also note that 20 MW for four sec is 5MW/sec or 300 MW/min. As long as the facility ramp rates do not exceed those ramp rates, such as following dispatch commands, then the change in active power would not be expected to meet the R1 criteria. The DT has considered using scan rate but at this time in the process has chosen to stay with the four second time period.	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	
As drafted, the thresholds in Requirement R1 place a large burden on IBR GOs to analyze events where unexpected changes in active power output occur and events where IBRs respond correctly to System events. We believe this goes against the intent of the SAR, which is “to ensure that any **unexpected** ceasing of current injection (partial or full) is analyzed by the applicable Generator Owner and mitigated to the extent possible.” In many cases, irradiance or wind speed data is not captured at such a high resolution from MET stations or it could be limited by data loggers in the field. The thresholds in R1 would result in significant work on the backend to isolate unexpected changes in active power output from changes associated with resource availability or even changes associated with an expected response to a System event. Consider utilizing SCADA scan rates rather than seconds in the threshold criteria.	
Likes 0	
Dislikes 0	
Response	
There is no specific way to define ""unexpected"" operation, and the use of that term caused considerable discussion about the definition. Rather than define unexpected, the DT noted clear cases of operational events that cause power changes (expected operation). While this may highlight the additional variables that impact the review, these variables must still be reviewed, even with a larger percentage, to classify partial reductions as unexpected. Also note that 20 MW for 4 sec is 5MW/sec or 300 MW/min. As long as	

the facility ramp rates do not exceed those ramp rates, such as following dispatch commands, then the change in active power would not be expected to meet the R1 criteria.

The DT has considered using scan rate but at this time in the process has chosen to stay with the 4 second time period.

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
The percentage of change in active power output identified in R1 should be put back to 20% of the plant's gross nameplate rating as in draft 1 instead of 10%.	
Likes 0	
Dislikes 0	
Response	
The DT team considered making changes and decided to remain at 10%. See other responses for more information.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends clarifying Requirement R1 to state that the GO shall implement a documented process to identify all changes in active power, not just changes in active power output. The Technical Rationale appears to support this its use of the phrase "changes in active power".	

Additionally, Texas RE recommends clarifying Requirement R1 to indicate whether the changes in active power correspond with the duration of the system disturbance. If the intent of the SDT to capture decrease in active power output during any disturbance event regardless of the duration of the disturbance, Texas RE recommends the following revisions. Additionally, Texas RE further asserts that the exemptions in R1 for loss of transmission facilities should apply only to radial facilities and not to locations where multiple transmission lines are terminated at the Point of Interconnection (i.e. loop fed transmission stations or substations). Texas RE's proposed revisions to the language in R1 are provided in bold below:

R1. Each applicable Generator Owner shall implement a documented process to identify changes in active power **output** that are the greater of 10% of the plant's gross nameplate rating or 20 MW, and occurring **within during** a **four second** period **that is no longer than 4 seconds**. Changes in active power for the following are excluded: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

- Changes associated with intermittent primary energy source2 availability;
- Resource dispatch, resource ramping, planned outages, or planned resource testing; or
- Loss of Transmission Provider's **radial** facilities **to the Point of Interconnection**

Likes 0	
Dislikes 0	

Response

The DT added complete loss to the change specification. DT made changes to R1 considering the Texas RE comments.

Scott Thompson - PNM Resources - 1,3,5 - WECC

Answer	
Document Name	

Comment

Yes, PNM supports the comments of EEI.

Likes 0	
Dislikes 0	

Response

Thank you for comment, please see the DT response to EEI's comment.

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

Kim Thomas – Duke Energy	
Answer	Y/N
Document Name	(if an attachment is provided by submitter)
Comment	
Duke Energy requires more information to adequately assess alternatives associated with FERC Order 901.	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
Thank you for the comment.	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Until Avista owns BPS IBR's generation, the standard has no effect on Avista. If we own IBR generation, we will need digital fault recorders (DFR's) installed to comply with the recording requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
Until we own BPS IBR's generation, the standard has no effect on us. If we own IBR generation, we will need digital fault recorders (DFR's) installed to comply with the recording requirements.	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
Until Avista owns BPS IBR's generation, the standard has no effect on Avista. If we own IBR generation, we will need digital fault recorders (DFR's) installed to comply with the recording requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy offers no alternatives toward the cost effectiveness of these recommendations.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment.	
Patricia Ireland - DTE Energy - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	
Invenergy is not in a position to comment on the overall cost-effectiveness of the proposed standard as it relates to BES reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
Invenergy is not in a position to comment on the overall cost-effectiveness of the proposed standard as it relates to BES reliability.	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company believes that perhaps determining subsections of the North American electric grid where this detailed monitoring and analysis is most needed rather than requiring it across the entire geographic area is an alternative and more cost-effective option to address the recommendations in the FERC Order. The system stiffness to voltage and frequency fluctuations should be accounted for in regions where the IBR facilities are not likely to be affected by abnormal system condition events. Any possible reduction in the number of facilities required to install this equipment is a direct cost reduction. Souther Company suggests the SDT remove the documented process and just state the GO shall perform a Root Cause Analysis of the performance deviation as there is no need to do all of the documented process steps. Then require the GO shall have documented evidence it performed an RCA on events that qualify.	
Likes 0	
Dislikes 0	
Response	
System strength is not the only indicator of potential for unexpected IBR loss or reductions in active power. Impact of system stiffness on IBR operation varies among IBR plants. Therefore, the DT does not view system strength or other available metrics as valid predictors of system areas with a higher likelihood of IBR performance issues addressed in PRC-030. Need site level monitoring to avoid system-level issues (e.g., coincidental tripping). PRC-030 does not require any specific monitoring methods or equipment. PRC-030 is independent of PRC-028, but it could use data requirements in PRC-028. Documented process is needed to review approach to identifying events to verify parameters are appropriate to capture IBR performance issues applicable under PRC-030.	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
AECI supports comments provided by the NAGF	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
The MRO NSRF does not believe that this is cost-effective as currently proposed. Please see the MRO NSRF's other responses to questions. Perhaps determining subsections of the North American electric grid where this detailed monitoring and analysis is most needed rather than requiring it across the entire geographic area. The system stiffness to voltage and frequency fluctuations should be accounted for in regions where the IBR facilities are not likely to be affected by abnormal system condition events. Any possible reduction in the number of facilities required to install this equipment is a direct cost reduction.	
Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Thank you for the comment, this will be passed along to the DT.	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 2	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power supports MRO’s NERC Standards Review Forum’s (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Tri-State supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
The Standard should be focused on sections of the grid where these disturbances have caused problems. Throwing every conceivable benefit to planners does not ensure that there will be any improvement in reliability. The BAs and the RCs have their work cut out for them and must be or become knowledgeable enough to identify the needs. The real problem is the loss of spinning inertia. There should be a moratorium on retiring generations until solutions are in place and grid stability is restored.	
Likes 0	
Dislikes 0	
Response	
Although some disturbances are reoccurring, past IBR performance issues are not necessarily indicative of future performance issues. System strength is not the only indicator of potential for unexpected IBR loss or reductions in active power. Impact of system stiffness on IBR operation varies among IBR plants. Therefore, the DT does not view system strength or other available metrics as valid predictors of system areas with a higher likelihood of IBR performance issues addressed in PRC-030.	
Alison MacKellar - Constellation - 5	

Answer	Yes
Document Name	
Comment	
Constellation supports NAGF comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation supports NAGF comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	

Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	Yes
Document Name	
Comment	
This standard is essentially an extension of MOD-033 and PRC-002. Modifications of these standards should be made instead of a new standard created since this is not to analyze trip events but to analyze continuous system behavior.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. PRC-002 is associated with the PRC-028 project. The DT does not see link between MOD-033 and PRC-030.	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
SMEs responded with the following “This standard is essentially an extension of MOD-033 and PRC-002. Modifications of these standards should be made instead of a new standard created since this is not to analyze trip events but to analyze continuous system behavior.”	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. PRC-002 is associated with the PRC-028 project. The DT does not see link between MOD-033 and PRC-030.	
Kevin Conway - Western Power Pool - 4	
Answer	Yes

Document Name	
Comment	
Yes, the Drafting team should identify specific performance criterion and require GOs who own IBR resources to meet that performance level. Event Analysis should be completed consistent with Standards like PRC-002, PRC-003 and PRC-004. The key is that the standards must state what the performance measurement is, and then through reporting and auditing compliance would be clearly objective.	
Likes 0	
Dislikes 0	
Response	
PRC-029 outlines the performance criteria and PRC-030 describes monitoring thresholds and subsequent investigative and corrective actions.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	

NV Energy agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Michael Goggin - Grid Strategies LLC - 5	
Answer	
Document Name	
Comment	

To address the concerns we expressed in answer to question 1 above regarding the burden on generators of screening out changes in output that are not caused by disturbances, the best solution may be to remove most if not all of R1, and instead rely on analysis requests initiated by the Reliability Coordinator, Balancing Authority, or Transmission Operator following a disturbance event per R2. This would remove the inefficient “needle in the haystack” burden on generators under R1 to screen every output change event to find the small subset that are due to disturbances, and instead only focus resources on reviewing disturbance events that coincided with a change in output. Because many generators do not have synchrophasors or other equipment required to determine when grid disturbances have occurred, it makes more sense for the analysis to be initiated by a request from the RC, BA, or TO.

We also reiterate our request from the last comment period to add a requirement to R2 that the RC, BA, or TO must file its request within 15 days of the disturbance event. This will ensure that the GO has at least five days to pull data before it is overwritten, given that the data retention period in the current draft of PRC-028 R7 is 20 days.

Finally, the requirement on the generator owner in 2.1.4 for “Determination of the susceptibility of its other inverter-based resource facilities to similar events” appears to be unreasonable if not unworkable. A company that owns multiple IBR plants typically uses different equipment and settings across its plants, and some may be wind plants while others are solar plants, so there is no reason to assume its other plants have the same susceptibility simply because they have the same owner. At minimum, the requirement should be clarified to specify whether non-BES IBR plants owned by the same owner must be assessed as part of compliance with 2.1.4., whether

projects owned by the same parent company but are actually separate LLCs must be assessed as part of compliance with 2.1.4., and other such details.	
Likes 0	
Dislikes 0	
Response	
Regarding applicability of the Standard, the Project 2023-02 SAR states: “The Functional Entities that the proposed standard would apply to are the inverter-based resource Generator Owners. This standard will also give authority to the RC, TOP, or BA to initiate an analysis by a GO if abnormal performance issues are identified.” It could be good practice to request and collect data within a certain number of days to support data availability per PRC-028. However, this does not need to be a requirement in PRC-030. Generator Owner is applied from the NERC registration perspective.	
Scott Thompson - PNM Resources - 1,3,5 - WECC	
Answer	
Document Name	
Comment	
By making EEI's suggested changes to R1, that should lessen the administrative cost associated with the standard. By not capturing everyday and common occurances, operational costs required to remain compliant with the standard should decrease.	
Likes 0	
Dislikes 0	
Response	
R1 has exceptions intended to filter every day, common occurrences and instead focus on unexpected partial of full loss of IBR plant active power output. See response to suggested changes to R1.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	

Document Name	
Comment	
Ameren agrees with NAGF's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Douglas Darrah - Clearway Renewable Operation and Maintenance LLC - 5 - MRO,WECC,Texas RE,RF	
Answer	
Document Name	
Comment	
Clearway will need more information to evaluate the proposed approach.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	
Document Name	
Comment	

N/A	
Likes 0	
Dislikes 0	
Response	
Thanks for the comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI has no suggestions for alternatives in addressing the associated FERC Order 901 directives that are being covered within this project.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
The definition for Inverter Based Resource (IBR) was approved by industry in April under Project 2020-06. We do not agree with inserting the uncapitalized version of IBR into 4.2 Facilities section because it is unbounded and insufficient to identify the Facilities applicable to this Standard, as required in the Rules of Procedure (Appendix 3a, Standard Processes Manual). Furthermore, these definitions are the	

foundation of several ongoing projects in response to FERC Order 901, where FERC "directs NERC to submit new or modified Reliability Standards that address specific matters pertaining to the impacts of IBRs on the reliable operation of the BPS."

It is imperative that the standard drafting teams for this project as well as the 2021-04 (PRC-002 and PRC-028) and 2020-02 (PRC-029 and PRC-024) assure a coherent way of addressing the inclusion and exclusion of IBRs in current and upcoming standards. These three different projects have all used different ways of drafting up section 4.2 of the standard.

The following comments are specific to PRC-030-1, Requirement R1:

- Add an exclusion for active power changes linked to frequency regulation and power limitations/runback ordered by the TO.
- Add an exclusion for faults inside the IBR plant.

Likes 0	
Dislikes 0	

Response

The IBR definition was approved with an invalid unenforceable term within the term. The IBR term is out for ballot again and will be closing before PRC-030-1 is posted. The PRC-030-1 standard will include the capitalized IBR term in the standard.
The DT added an R1 exclusion for Frequency Response. Power limitations/runback are addressed by the second bullet point exclusion elements related to ramping and dispatch.
Thank you for the suggestion the team will discuss these exclusions and decide if they should be included.

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	
Document Name	

Comment

No comment on cost-effectiveness. WECC leaves that to the applicable entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.	
Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
Thank you for the comment.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost-effectiveness.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment.	

3. Does the entity have any concerns regarding the 2023-02 Implementation Plan? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

Kim Thomas – Duke Energy	
Answer	Yes
Document Name	

Comment	
Duke Energy suggests extending Implementation Plan timeline to 18 months due to budgeting, planning, procurement, installation/implementation, and vendor concerns.	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
Thank you for the comment.	

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

Answer	No
Document Name	
Comment	
FirstEnergy has no objections to the proposed Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	

Not applicable to Avista at this time	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
Not applicable to us at this time since we do not own any IBR generation.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Not applicable to Avista at this time	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment. See the Responses to EEI and MRO comments.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI has no objections to the proposed Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company does not have any concerns with the Implementation Plan with acknowledgment of changes needed as noted in the previous questions and in the Additional Comments below.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	

Answer	No
Document Name	
Comment	
NV Energy agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment.	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Thank you for the comment.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Scott Thompson - PNM Resources - 1,3,5 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment.	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2024	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	

Comment	
For many entities the Standard, as proposed, will require more than 6 months to implement and be compliant with. Entities should be given 6 months to create a plan and submit it to the Regional Entity for approval. The plan would include when the entity the anticipated date when all facilities can be brought up to compliance.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the team has extended time frame to 12 months.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Implementing changes to the active power output will require software and possibly hardware modifications or additions. Having only six months to design and implement this modification is not reasonable. Instead, AEP recommends an implementation period of 18 months.	
Likes 0	
Dislikes 0	
Response	
The implementation plan is to develop and implement the process to identify events. Hardware changes are not foreseen as necessary to comply with the Standard.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	

Comment	
Having the “process” mandated by Requirement R1 within 6 months is probably reasonable. However, having the “ability” to implement the process within 6 months, if it doesn’t already exist with the plant, will be nearly impossible. It could require a design change, equipment procurement, and plant modification, which could easily take a year or longer, given current manpower and supply chain issues. Additionally, most utilities would likely have to secure the services of a limited number of contracting companies with the necessary experience to do the work.	
Likes 0	
Dislikes 0	
Response	
Hardware changes are not foreseen as necessary to comply with the Standard.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation supports NAGF comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see the response to NAGF responses.	
Alison MacKellar - Constellation - 5	

Answer	Yes
Document Name	
Comment	
Constellation supports NAGF comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see the response to NAGF responses.	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
The implementation plan should be 365 days instead of 90 days to allow for any control changes that might be required. A process may need to be added to allow extensions of implementation based on potential supply chain issues.	
Likes 0	
Dislikes 0	
Response	
Hardware changes are not foreseen to be required to comply with the Standard.	
Patricia Ireland - DTE Energy - 4	
Answer	Yes

Document Name	
Comment	

The prerequisite section states:

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

- PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
- PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Generating Resources Applicable Entities"

Should be changed to:

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

- PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
- PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Generating Resources Applicable Entitie"

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

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

PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Generating Resources Applicable Entitie"

Likes 0	
Dislikes 0	

Response

Thank you for the comment, the team will consider this change in the next posting.

Ruchi Shah - AES - AES Corporation - 5

Answer	Yes
Document Name	
Comment	
AES CE agrees with NAGF’s suggestion to extend the proposed Implementation Plan timeline from 6 months to 12 months. This additional time will allow us to explore/configure automation for IBR event identification, event analysis process development/optimization, and corrective action plan development.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see the response to NAGF responses.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation requests the proposed Implementation Plan timeline be changed from 6 months to 12-24 months. This will help generator owner/operators to explore & if purchase - configure automation for IBR event identification, plus event analysis process development and corrective action plans.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see the response to NAGF responses.	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
SMUD agrees with the NAGF's suggestion to extend the proposed Implementation Plan timeline from 6 months to 12 months.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see the response to NAGF responses.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF requests the DT to consider extending the proposed Implementation Plan timeline from 6 months to 12 months. This additional time will allow GOs to explore/configure automation for IBR event identification, event analysis process development/optimization, and corrective action plan development.	
Likes 2	JEA, 1, McClung Joseph; Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	

Thank you for the comment, the team has considered and will be making this change in the next posting.
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	Yes
Document Name	

Comment
There is not clarity in the Implementation Plan as it hinges on the Approval of PRC-028 and PRC-029. PRC-028 has a proposed phased in Implementation Plan extending to 2030. While the PRC-028 Standard itself becomes “effective” the Requirements within the Standard are not applicable at the same time which could affect the applicability of inverter-based resources in PRC-029 and PRC-030. WECC suggests the DTs of each Project (PRC-028/029/030) draw a timeline regarding implementation dates so the industry is clear on the expectations. Leaving it to interpretation without clarity in expectations is a detriment for reliability. PRC-030 makes no distinction between existing inverter-based resources and future inverter-based resources but PRC-028 does. Without clarity provided by the DTs, the implementation of these Standards to mitigate the identified risks will not be successful for entities (both from a reliability and compliance perspective.)

Likes 0	
Dislikes 0	

Response
Thank you for the comments and support, the team will look into these changes.
Douglas Darrah - Clearway Renewable Operation and Maintenance LLC - 5 - MRO,WECC,Texas RE,RF

Answer	Yes
Document Name	

Comment

Clearway support the NAGF's proposal to extend the Implementation Plan timeline from 6 months to 12 months. As the Generator Owner for over 40 NERC-registered IBRs, Clearway is concerned that the proposed six-month implementation timeline will not give GOs enough time to comply with the proposed standards. Developing the automated monitoring mandated by R1 along with the analysis and reporting procedures required by R2, R3, and R4 will require substantial work to be completed by Clearway's SCADA and engineering teams. A 12-month timeline will meaningfully lessen the compliance burden created by the proposed standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see the response to NAGF responses.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
AECI supports comments provided by the NAGF	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see the response to NAGF responses.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

The Prerequisite section should state that the standards must be approved before “or concurrently with” PRC 028 and 029 to allow for a scenario in which a package of all the standards is submitted to FERC concurrently.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, this is a positive add that the team will consider adding.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with NAGF's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see the response to NAGF responses.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
Considering the amount of data that will need to be filtered, we propose the Implementation Plan be amended to allow entities at least 12 months to implement their process(es) to identify and analyze qualifying events. Alternatively, consider linking the Implementation	

Plan for PRC-030-1 to that of PRC-028-1, given that the required monitoring equipment may be useful in the identification and analysis of qualifying events.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the team has decided to extend the date from six months to twelve months.	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	
Considering the amount of data that will need to be filtered, we propose the Implementation Plan be amended to allow entities at least 12 months to implement their process(es) to identify and analyze qualifying events. Alternatively, consider linking the Implementation Plan for PRC-030-1 to that of PRC-028-1, given that the required monitoring equipment may be useful in the identification and analysis of qualifying events.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the team has decided to extend the date from six months to twelve months.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	

The implementation period should be increased to 2 years to allow for any equipment changes or upgrades needed to comply with the standard.

Likes 0	
Dislikes 0	

Response
Thank you for the comment, the team has decided to extend it to twelve months from six months to fit in with the regulatory mandates.

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

Kim Thomas – Duke Energy	
Answer	
Document Name	

Comment
Duke Energy agrees with and recommends implementing the following summarized EEI comments - see EEI submittal for a detailed description of each comment: **EEI COMMENTS** General Comment: Do not agree with the use of non-glossary terms where glossary terms are available and the use of glossary terms that are not capitalized – see EEI submittal for detailed descriptions and potential resolution(s). Applicability Section Comments: Do not agree with the non-industry approved use of Footnote 1 to expand the definition of IBRs and the lack of a technical or SAR justification for the addition of VSC-HVDCs – see EEI submittal for detailed descriptions and potential resolution(s). Requirements Comments: Requirements R2 & R3: Do not agree with the inclusion of requirements that are not clearly defined or sent from multiple registered entities (i.e., RC, BA or TOP) which creates regulatory confusion and undue burden, fails to define compliance responsibility, for functional entity responsibilities not listed in the Applicability section of the Standard – see EEI submittal for detailed descriptions and potential resolution(s). Requirement R4, Subpart 4.3: Suggest adding “Upon Request” to Subpart 4.3 for consistency with Requirement R2, Subpart 2.2 because there should not be a regulatory requirement to notify the RC regarding CAP actions, timetables change and when the CAP is completed, unless the RC specifically requests that the GO provide such notification – see EEI submittal for detailed descriptions and potential resolution(s). Additionally, Duke Energy agrees with and recommends implementing the following summarized NAGF comments - see NAGF submittal for a detailed description of each comment: **NAGF COMMENTS** Provide a technical explanation why in Requirement R2 Part 2.1.3, each applicable Generator Owner shall, within 60 calendar days,

provide a CAP or Technical Justification to the RC, BA, and TOP
Finally, Duke Energy submits the following comment for consideration:

DUKE ENERGY COMMENTS

Standard language consideration should be given to GOs reporting/corresponding to the TP instead of the RC for vertically integrated electric utilities.

Consider substituting the following language for R1 to enhance its clarity: "…identify changes in real power output that are at least 20 MW and greater than 10% of the plant's gross nameplate rating," and occurring during a period that is "within 4 seconds."
Revise Reliability Standard PRC-030-1 June 2024 Technical Rationale Document Figure 1.2: PRC-030-1 Flowchart to read 20 "MW" instead of 20 MVA.

Recommend modifying R1 language to read "…occurring during a period that is "within" 4 seconds." to clarify statement.

Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments

Response

See DT response to EEI and NAGF comments.

RC and TOP are responsible for real time operations and the DT believes communications should be with those entities.

DT has revised language in R1 to clarify MW thresholds and time window.

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	
Document Name	
Comment	

The time periods in R2 and R3 should be increased to 120 calendar days to allow time to determine the root cause and develop a Corrective Action Plan, especially if OEM support is required.

Likes 0	
Dislikes 0	

Response

The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance.

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2024

Answer	
Document Name	

Comment

Regarding R2, Generator Owners should report performance issues more promptly than 90 calendar days. That report only needs to detail the impact of the performance issue then the 90-day assessment would have details and the Generator Owner can complete analysis and develop a corrective action plan in 90 days. Revise R2 wording to:

R2. Each applicable Generator Owner, within 3 business days , shall report the impact of those performance issues to the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator and within 90 calendar days of identifying an active power change event pursuant to Requirement R1 or following a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the inverter-based resource(s) active power output, shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determination of the root cause(s) of change(s) in active power output;

2.1.2. Documentation of the facility's Ride-through performance including reactive power response during the event;

2.1.3. Assessment of any performance issues identified and if corrective actions are needed; and 2.1.4. Determination of the susceptibility of its other inverter-based resource facilities to similar events. 2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator R2. If performance issues and corrective actions were identified in Requirement R2 Part 2.1.3, each applicable Generator Owner shall, within 3 business days, report those performance issues to the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator and within 60 calendar days of completing the analysis in Requirement R2, develop one of the following and provide it to the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator. Reports do not have to include details for specific causes but shall provide detail regarding overall impact to the generator facility. NOTE: MISO is a party to these comments however has opted out of supporting the response to Question 4.	
Likes 0	
Dislikes 0	
Response	
The DT considered early notification of performance issues and has chosen not add a requirement.	
Rhonda Jones - Invenergy LLC - 5	
Answer	
Document Name	
Comment	

Invenergy thanks the drafting team for the opportunity to provide comments. **Footnote 1:** This does not align with the recently approved definition of Inverter-based Resource. If the drafting team intends to include other types of facilities not included in the IBR definition, then those facilities should be separately listed in the Applicability section, rather than as a footnote of BES IBR. **R4.3:** This should be removed or amended such that it is only upon request of the Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	
The DT has removed footnote 1 from the standard. The DT kept requirement R4.3 to ensure that the RC is aware of performance issues and when they are corrected.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
NV Energy agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
See DT response to EEI comments.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	

Document Name	
Comment	

Invenergy thanks the drafting team for the opportunity to provide comments.

Footnote 1: This does not align with the recently approved definition of Inverter-based Resource. If the drafting team intends to include other types of facilities not included in the IBR definition, then those facilities should be separately listed in the Applicability section, rather than as a footnote of BES IBR.

R4.3: This should be removed or amended such that it is only upon request of the Reliability Coordinator.

Likes 0	
Dislikes 0	
Response	

The DT has removed footnote 1 from the standard.

The DT kept requirement R4.3 to ensure that the RC is aware of performance issues and when they are corrected.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	
Comment	

Southern Company offers the following comments and questions for the SDT:

- Not seeing relationship of footnote 1 with Facilities 4.2.1.
- Recommend R1 state "… 4 continuous seconds…"
- In R1, delete the word "documented"
- In M1, change"(1) the documented process..." to "(1) implementation of a process for...".
- With the two changes above deleting "documented", item (2) in M1 can be deleted.

- In R2.1.1, be more direct by changing “Determination of the root cause(s)...” to “Determine the root cause(s)..”.
- In R2.1.2, be more direct by changing “Documentation of the facility’s...” to “Document the facility’s...”.
- R 2.1.2 remove “…including reactive power response during the event.” as it does not align with the purpose statement or R1. This is the only place Reactive Power shows up.
- In R2.1.3, be more direct by changing “Assessment of any performance...” to “Assess any performance ...”
- In R2.1.3, change the word “needed” to “indicated” to take into account the possibility of there being no changes available to affect the response of the IBR controls to the system disturbance.
- R2.1.4 should be removed. Although a good suggestion, in reality this would be difficult to prove and does not show up in the M2. GOs would naturally want to eliminate issues found if they thought they we systemic across multiple locations.
- Modify M2 to account for the possible request for results of the analysis by the RC, BA, or TOP by changing “Each applicable Generator Owner shall have dated documentation of the required analysis developed in accordance with...” to “Each applicable Generator Owner shall have dated documentation of the required analysis developed, and the delivery of the analysis when requested, in accordance with...”.
- R3 first bullet needs to remove this part of the sentence “…including other applicable facilities owned by the Generator Owner as identified in Requirement R2 Part 2.1.3…”
- R3 second bullet needs to remove the word “technical”. There are other reasons that a CAP would not be implemented, such as cost, plant near end of functional life, etc.
- Does the BA and TOP also need to appear in the new R4.3 since they appear in the new R3/M3?
- Was there a specific reason that the Transmission Planner and/or the Planning Coordinator was not also included in the RC/BA/TOP group each time they appear in the standard? It seems like the Planner may also be interested in the actual performance of the IBR facility.
- Purpose needs to read “Identify, analyze, and mitigate unexpected inverter-based resource (IBR) change of Real Power output. Real Power is a NERC glossary term.
- Change term “active power” to “Real Power” throughout.
- “reactive power”, if used, needs to be capitalized to “Reactive Power” throughout. (Glossary of Terms Used in NERC Reliability Standards)

Likes 0	
Dislikes 0	

Response

The DT agreed with many of your comments and made the following changes: -footnote 1 removed -R1 revised -R2 and subsequent sub-bullets revised -updated active power to real power per NERC glossary with appropriate capitalization DT did not add BA and TOP to R4.3 since the RC has ultimate responsibility to system reliability. TP and PC was not included since PRC-030 is an operational standard.

John Pearson - ISO New England, Inc. - 2	
Answer	
Document Name	
Comment	
Under R2, when it is necessary to analyze an event, the GO should notify the applicable Reliability Coordinator, Balancing Authority, or Transmission Operator much more timely than 90 calendar days and a notification should be made the next business day after the event occurred. The notification does not need to include any causal analysis but should provide performance details. The GOs analysis required per R2.1 can be performed within 90 calendar days as described but the RC/BA/TOP should be aware of the potential for such events in the meantime.	
Likes 0	
Dislikes 0	
Response	
The DT considered early notification of performance issues and has chosen not add a requirement.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	

Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
See response to NPCC comments.	
Scott Thompson - PNM Resources - 1,3,5 - WECC	
Answer	
Document Name	
Comment	
PNM supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
See response to EEI comments	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	

Ameren agrees with NAGF's comments.	
Likes 0	
Dislikes 0	
Response	
See response to NAGF comments	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

Regarding R2, Generator Owners should be required to promptly notify the RC/BA/TOP of performance issues before conducting the assessment that is contemplated in this requirement to be completed within 90 days. This would allow the RC/BA/TOP to then initiate its review process and request operational data before any retention periods have expired. The initial notification only needs to provide minimum levels of detail (e.g. date/time, unit, MW impact, any initial assessment). . The wording of R2 can be revised or a separate requirement could be created.

RX. Each applicable Generator Owner, shall, before the end of the next business day of identifying an active power change event, notify the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator of the event. The notification shall include at a minimum: date, time, unit, change amount, and any initial known causes.

Also, ERCOT recommends modifying R2 to say the following:

R2. Each applicable Generator Owner, within 90 calendar days of identifying an active power change event pursuant to Requirement R1 or receiving a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a change in the inverter-based resource(s) active power output during or immediately after a Disturbance, shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determination of the root cause(s) of change(s) in active power output;

2.1.2. Documentation of the facility's Ride-through performance including reactive power response during the event;

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

2.1.4. Determination of the susceptibility of its other inverter-based resource facilities to similar events.

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

R3

For R3, the standard does not provide sufficient clarity about what sorts of technical justifications would justify not implementing corrective actions. For example, would cost be a sufficient ground? As written, the provision for a GO to not be required to implement corrective actions is too broad with no consideration to the reliability impact of not correcting. FERC has recently rejected similarly broad language in the context of NERC-proposed generator weatherization standards. *See* Order Approving Extreme Weather Reliability Standard EOP-012-2 and Directing Modification at p.41, FERC Docket No. RD24-5-000, 21-5-000 (June 27, 2024). Here, as in that case. leaving it up to the generator owner to interpret what it meant to have a technical constraint is unacceptable. The criteria should be "objective, unambiguous, and auditable". *Id.* Moreover, the commission directed in that order that such communications should be confirmed by a reliability entity (e.g. NERC/REs). The need for NERC or RE review should be considered by NERC and the SDT in light of this order, just as the NERC Project 2020-02 SDT is doing for PRC-029.

It is also unclear whether there is any difference between corrective actions “not being applied” and such actions not being “implemented.” The current phrasing seems at best redundant. ERCOT also believes that CAPs that materially modify the generator’s response characteristics from those based on existing models should be evaluated by the RC/BA/TOP prior to the GO making such changes, and that models should be updated consistent with NERC recommendations in the 2022 Odessa event report. ERCOT does not believe the obligation to update models is adequately captured in the current MOD standards and recommends this be included in a sub requirement to R4 as follows: “Update any dynamic models to reflect the corrective actions if necessary”. ERCOT also recommends that the Corrective Action Plan should require corrective actions to be implemented within a reasonable timeframe to guard against egregiously long implementation periods. Finally, ERCOT recommends that the first sentence be clarified to more accurately align with R2’s requirement that the GO must identify only a **need** for a CAP within 90 days. So the opening sentence should read: “If performance issues and **a need for** corrective actions were identified in Requirement R2 Part 2.1.3, ...”	
Likes 0	
Dislikes 0	
Response	
The DT considered early notification of performance issues and has chosen not add a requirement. The DT will provide examples of technical justifications in the Technical Rational document. The DT revised the language for R3 bullet 2.	

Revision to the MOD standards addressing generator modeling are forthcoming.

The CAPs include a time table to achieve a solution to address the issue. It is difficult to develop a standard timeline that would be applicable to the wide range of performance issue solutions.

DT made changes to R2.1.3.

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports comments provided by the NAGF	
Likes 0	
Dislikes 0	
Response	
See DT comments to NAGF.	

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	

The applicabilities of PRC-028, PRC-029, and PRC-030 need to be aligned. E.g. A TO that owns the VSC-HVDC connection for offshore wind is subject to PRC-029 but not PRC-028 or PRC-030.

Likes 0	
Dislikes 0	
Response	
The DT removed footnote 1. The 3 drafting teams of PRC-28, PRC-29, and PRC-30 have aligned applicability.	
Douglas Darrah - Clearway Renewable Operation and Maintenance LLC - 5 - MRO,WECC,Texas RE,RF	
Answer	
Document Name	
Comment	
Clearway supports the additional comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
See comments to NAGF.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
WEC Energy Group agrees with the MRO NSRF about adding exclusions to the applicability section of the proposed standard to ensure that PRC-030 R1 does not include balance of plant (BOP) Protection Systems already covered under PRC-004-6.	

WEC Energy Group supports all NAGF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
See response to MRO NSRF, NAGF, and EEI comments. DT added exclusions for protection system operations in scope for PRC-004	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	MRO-NSRF_2023-02-PRC-030_UCF_04-17-2024_FINAL.docx
Comment	
· §4. Applicability The MRO NSRF reiterates its recommendation that the SDT add exclusions to the applicability section of the proposed standard to ensure that PRC-030 R1 does not include balance of plant (BOP) Protection Systems already covered under PRC-004-6. An example would be PV & wind generation 34.5kV collection system Protection Systems. As the proposed standard is currently drafted there is no clear distinguishing language. It is suggested that the footnote information be included in the §4. Applicability to eliminate the footnote altogether. · Requirement R1: The MRO NSRF would like to reiterate that Requirement R1 “documented process to identify unexpected changes” is not a requirement within the SAR’s scope. According to the SAR, Generator Owners need to “analyze performance issues identified at their facilities”. Having a documented process is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit.	

It is suggested that the footnote information be included in the bullet of R1 to eliminate the footnote altogether.

In R1, suggest the deletion of the word “documented”

In M1, suggest that item 1 be changed from “(1) the documented process...” to “(1) implementation of a process for...”.

With the two changes above deleting “documented”, suggest that item (2) in M1 be deleted.

· Requirement R2:

The MRO NSRF does not agree with allowing the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA) to be able to request an analysis of any a change in “the inverter-based resource(s) active power output”; the criteria for this analysis shall be the same criteria as outlined in Requirement R1.

The MRO NSRF does not agree with the 90 calendar day timeframe and believes it should be 120 days similar to PRC-004-6.

In the new R2, R2.1.1, suggest being more direct by changing “Determination of the root cause(s)...” to “Determine the root cause(s)..”.

In the new R2, R2.1.2, suggest being more direct by changing “Documentation of the facility’s...” to “Document the facility’s...”.

In the new R2, R2.1.3, suggest being more direct by changing “Assessment of any performance...” to “Assess any performance ...”

In the new R2.1.3, suggest changing the word “needed” to “indicated” to take into account the possibility of there being no changes available to affect the response of the IBR controls to the system disturbance.

In the new R2, R2.1.4, suggest being more direct by changing “Determination of the susceptibility...” to “Determine the susceptibility...”.

· Requirement R3:

The MRO NSRF would like to reiterate that being required to provide either a ‘Corrective Action Plan or justification of why corrective actions will not be applied to the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA)’ is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit, if the RC, BA & TOP do not need or want this data & analysis.

· Requirement R4.3:

The MRO NSRF would like to reiterate that the proposed Requirement R4.3 is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit, if the RC, does not need or want this information.

· Requirement R1 & R2

The MRO NSRF would also like to reiterate that most inverter based resources are owned by independent power producers (IPP), as such, it is their best interest to ensure a high availability of the Facility and analyses such as the ones being proposed in PRC-030 are not only in the interest of reliability, but also in the interest of the IPP so long as the criteria for performing an analysis is reasonable and cost effective. The MRO NSRF appreciates the efforts the Standards Drafting Team has put forth and is suggesting the following criteria for the proposed PRC-030 analysis based on the aforementioned information:

Removal of Requirement R1 in its entirety and combining it with the proposed Requirement R2 as follows:

R2. Each applicable Generator Owner, within 120 calendar days of either a, capability1 change of greater than 20% of the generation Facilities gross capability1 nameplate or following a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a capability1 change of greater than 20% of the generation Facilities gross nameplate capability1, shall, excluding:

· Changes associated with intermittent primary energy source (fuel supply: wind, solar irradiance) availability;

· Resource dispatch, resource ramping, planned outages, or planned resource testing; or

· Loss of Transmission Provider's interconnection facilities.

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in capability1; 2.1.2. Document the Facility's Ride-through performance including reactive power response during the event; 2.1.3. Assess any performance issues identified and if corrective actions are needed; and 2.1.4. Determine the susceptibility of its other inverter-based resource facilities to similar events. 2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator. 1: A generation resource capability is based on availability of individual generating units that compromise the Facility multiplied by the individual generating unit's nameplate.	
Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
DT added exclusions for protection system operations in scope for PRC-004 DT decided to leave document process in R1. DT incorporated footnote 2 into R1.	

DT determined that entities responsible for system reliability need an appropriate avenue to trigger evaluation of system events that are not in scope for R1. R1 intended to capture most events but was not able to be designed in a way to capture all events. The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The 120 day timeframe in PRC-004 was intend to cover wide scale weather events such as hurricanes. DT accepted wording changes in R2 and sub-bullets. RC, BA, and TOP have the responsibility for reliability and hence the need to know performance issues associated with such issues. DT discussed changes of thresholds and decided to keep the 10% nameplate with a 20 MW minimum.

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 – RF	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thanks for the comment.	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

EEI offers the following suggested changes to PRC-030-1:

General Comment: Throughout this Reliability Standard there is use of non-glossary terms where glossary terms are available and should be used. (e.g., active power vs. Real Power) While in other cases glossary terms are used but not capitalized. (e.g., reactive power vs. Reactive Power) Greater efforts should be made to use NERC Glossary terms where appropriate and capitalize those terms, as required.

Applicability Section Comments:

Footnote 1: EEI does not support Footnote 1 because it expands the definition of IBRs beyond what was recently approved by the industry, noting the footnotes expansions the definition of IBR to include VSC-HVDC. Furthermore, there was no technical justification for adding VSC-HVDC and the SAR did not include adding VSC-HVDC systems to this project. For this reason, we ask that the definition of IBR not be expanded through footnotes and suggest that the DT submit a technical justification for adding VSC-HVDC systems to the applicability section of this Standard, rather than redefining an approved definition in a footnote.

To address our concerns related to Footnote 1 we suggest that if VSC-HVDC systems are to be classified as IBRs, then the approved definition should be pulled by NERC and resubmitted with those resources added to the definition and resubmitted to the industry for approval. Alternatively, VSC-HVDC systems could be defined separately, and that definition submitted to the industry for approval. In both cases, a technical justification should be submitted to the industry that defines the issues and risks to BPS reliability that VSC-HVDC systems pose. Lastly, this project has been aligned with FERC Order 901, noting that IBR related performance requirements for ride - through are to be completed and submitted to FERC by Nov. 4th. Yet, the DT expands the definition of IBRs by adding VSC-HVDC systems complicating industry approval without any technical justification for expanding the definition.

Requirements Comments:

Requirements R2 & R3: EEI is concerned with the inclusion of requirements that are not clearly defined or sent from multiple registered entities (i.e., RC, BA or TOP). This creates regulatory confusion and places IBR-GOs in a position where they may need to comply with any number of entities without clearly defining who is actually responsible. (See Requirement R2) Moreover, the identification of multiple entities, who could be responsible, creates a situation where IBR-GOs will have reporting obligations to multiple entities because no single entity is identified as being responsible. (See requirement R3) We further note that none of the entities identified (i.e., RC, BA, or TOP) are identified within the Applicability section of this proposed Reliability Standard. Yet, all of this places considerable compliance burdens on the IBR-GOs who will need to analyze and resolve (R2) those issues at the request of any of these entities and provide

notification regarding CAP or technical justification, regarding their inability to fully resolve the issues, without any of these entities having clearly defined responsibilities within this standard. **Requirement R4, Subpart 4.3:** EEI suggests adding “Upon Request” to Subpart 4.3 for consistency with Requirement R2, Subpart 2.2 because there should not be a regulatory requirement to notify the RC regarding CAP actions, timetables change and when the CAP is completed, unless the RC specifically requests that the GO provide such notification.	
Likes 0	
Dislikes 0	
Response	
DT has adopted changes to reflect glossary terms. DT removed footnote 1. RC, BA, and TOP have the responsibility for reliability and hence the need-to-know performance issues associated with such issues. RC has the responsibility for reliability and hence the need-to-know performance issues and CAP associated with such issues.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
R2.1- Identifying the root cause of the event and determining the corrective actions required will likely require the IBR manufacturer’s collaboration. How can this be done if the manufacturer has gone bankrupt or is unwilling to collaborate. Please indicate what to do for such a situation.	

R2.2 - Why provide the analysis results only if requested. Every analyzed problematic situation report should be transmitted. R3 - The first bullet, when the CAP identified required modifications to the IBR, should require the OEM to inform all GO using the same technology a CAP is required for their facility.	
Likes 0	
Dislikes 0	
Response	
GO should seek all reasonable forms of mitigation to fix the problem. To the extent that is not available then it could be a consideration for technical justification. The DT believes that having the analysis of performance issues provided upon request is a reasonable middle ground between GOs and RC, BA, and TOPs. Currently, NERC has no jurisdiction over OEMs.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
WECC believes footnote 1 is not cohesive with the phrase to which it is attached and should be removed as it has no bearing or context within this Standard. Evidence Retention Section needs some adjustments as there are possible differences in the retention requirements for R2 materials. The first bullet indicates saving R2 material for 36 calendar months AFTER completion of the Requirement. The second bullet indicates saving R2 material for “36 calendar months following the completion of each CAP, completion of each evaluation, and completion of each declaration”. WECC suggests the following: “The Generator Owner shall keep data or evidence of Requirement R1 Measure M1 for 36 calendar months.	

The Generator Owner shall keep data or evidence of Requirement R2 Measure M2 and Requirement 3 Measure M3 for 36 calendar months after the development of a Corrective Action Plan.

The Generator Owner shall keep data or evidence of Requirement R4 Measure M4 for 36 calendar months after changes in any Corrective Action Plan actions or timetables or completion."

Severe VSL for R2 needs to capitalize "Ride-through".

VSLs for Requirement R3 need to consistently use "calendar days" as called out within Requirement R3. Consider moving the timeframe to alleviate concerns about "implementation"—Example "The responsible entity failed, within 60 to 90 calendar days, to develop a CAP or provide a technical justification addressing why corrective actions will not be applied nor implemented."

Without any time requirement to complete a CAP and an evidence retention timeframe of 36 calendar months, how would anyone ascertain the CAP was not implemented if the timeframe went past 36 calendar months for completion of activities?

Technical Rationale. At the top of page 2 the sentence "Requirement R3 requires a Corrective Action Plan (CAP) or technical justification when corrective actions are needed" should be adjusted to say "….when, respectively, corrective actions are needed or will not be applied nor implemented". As currently written the latter part of sentence does not appear correct. The Figures should reflect "calendar days" not simply days. Figure 1.2 indicates a change greater than 20 MVA but Requirement R1 language indicates 20 MWs. MVA is a common SCADA-driven point (Facility Ratings are provided in MVA and regularly evaluated by every major EMS vendor for powerflow analysis.)

The exclusions included in Requirement R1 should be in Requirement R1 flow. Consider a decision box under the "10%" that shows "Exclusions in R1" with a flow to "Non-applicable Event". In the Requirement R2 section there should be a Yes path from "Unexpected Performance" to a new box "Performance issues and Corrective Action identified" with a Yes path to R3 and a No path to "No mitigation". Note the rigor of analysis could come into question if an event occurred and the analysis did not identify any corrective actions. Changes to "calendar days" should be made to reflect the Requirement language. "Ride-through" should be hyphenated (page 5 second paragraph.) The Technical Rationale uses the more acceptable language regarding applicability to other units versus the ambiguous "determination of the susceptibility" language within the Standard. Under requirement R3 the sentence "When the IBR Performance issue cause(s) is identified in Requirement R2 or Requirement R3 requires Generator Owner(s) to develop a CAP or provide a technical justification that addresses why corrective actions will not be applied nor implemented" is not a well-developed sentence. Should “or” be removed after “R2”? There is reference to development of multiple CAPs for multiple causes which is valid. However, the analysis must be complete within 90 calendar days and the CAP(s) completed within 60 calendar days of completion of the analysis.

Interconnection requirements historically did not reach the detailed level that analysis of events have revealed. Indicating that older interconnection requirements are a technical justification not to address issues effectively grandfather’s the risk into the ecosystem providing for continued unreliable operations. By doing so, this Standard is not mitigating the risk identified. Additionally, “material modifications” is a term that was written out of FAC-001/002 and should not be used. A technical justification is equipment limitations (not interconnection requirements). Operating limitations should be placed on IBRs not able to meet current interconnection requirements to mitigate the risk posed.

Technical Rationales are to provide reasons why language was provided and not ways to be compliant. The technical justification is more of Implementation Guidance language than a Technical Rationale. While WECC agrees that there may be technical justifications provided, the first example in the Technical Rationale is not technical in nature. If an inverter-based resource could technically not adjust a setting, that would be a technical rationale (and justification).

Likes 0	
Dislikes 0	

Response

Footnote 1 was removed.

DT will look into the retention issues noted.

Thank you for the comments. DT will incorporate these comments as feasible.

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	
Document Name	

Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI), North American Generator Forum (NAGF), and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 4	
Likes 0	
Dislikes 0	
Response	
See response to EEI, NAGF and MRO NSRF comments.	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	
Document Name	
Comment	
Exelon agrees with the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
See response to EEI comments.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE has the following additional comments:

- Requirement R2, subpart 2.2 seems to require that an additional request be made by the RC, BA or TOP for the analysis results. Texas RE recommends the phrase “upon request” be removed from subpart 2.2. Please see the revision below (in bold).

2.2. **Upon request,** p**rovide** the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator

- Technical Rationale – The Figure 1.2: PRC-030-1 Flowchart should be revised to reflect the 20 MW requirement instead of 20 MVA.
- Technical Rationale - On Figure 1.2: PRC-030-1 Flowchart: Texas RE recommends adding a line from Technical Justification box to a new box “Notification to RC, BA, TOP” to match Requirement R3.

Likes 0	
Dislikes 0	

Response

The DT took these comments into consideration.

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	

Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
See response to MRO NSRF comments.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	

The NAGF provides the following additional comments for consideration:

Requirement R2:

The NAGF notes that any IBR data request initiated by the Reliability Coordinator (RC), Balancing Authority (BA), and/or the Transmission Operator (TOP) should be contained in its respective data request processes under IRO-010 and TOP-003.

Requirement 2.1.2: The NAGF recommends that this requirement should be included as part of the process created in Requirement R1. In addition, the NAGF is concerned with the potential for overlap with PRC-029.

Requirement R3: The NAGF seeks clarification as to why the Generator Owner must provide a CAP or technical justification to the RC, BA, and TOP.

Requirement R4.3: The NAGF recommends that the DT consider removing the requirement to notify the applicable Reliability Coordinator if CAP actions or timetables change and when the CAP is completed. To the extent the RC wants this information, they should request it under their data specification under IRO-010.

Likes 2	JEA, 1, McClung Joseph; Scott Brame, N/A, Brame Scott
Dislikes 0	

Response

RC, BA, and TOP have the responsibility for reliability and hence the need-to-know performance issues and CAP associated with such issues.

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	
Document Name	

Comment

Under the Facilities Applicability, Section 4.2.1 states “BES inverter-based resources” and the word “resources” is annotated by Footnote 1. Footnote 1 states “For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for inverter-based resources. In case of offshore wind plants connecting via a dedicated VSC-HVDC, the main power transformer is the onshore main power transformer.”

SMUD believes Footnote 1 is incorrect. Did the Standard Drafting Team (SDT) intend to word Footnote 1 in this manner, or should it be worded similar to Footnote 2 in the latest version of PRC-029-1 which states “For the purpose of this standard, “inverter-based resources” refers to a collection of individual solar photovoltaic (PV), Type 3 and Type 4 wind turbines, battery energy storage system (BESS), or fuel cells that operate as a single plant/resource. In case of offshore wind plants connecting via a dedicated VSC-HVDC, the inverter-based resource includes the VSC-HVDC system.”

It seems that Footnote 1 in the latest version of PRC-030-1 has been copied in error from PRC-028-1 Draft 3 Footnote 2, which does reference “main power transformers”.

Rather than using the term “BES inverter based resources” and defining “inverter based resources” with a Footnote, SMUD recommends that the PRC-030-1 SDT coordinate with the SDTs for PRC-028-1 and PRC-029-1, and use the glossary term IBR and its definition approved by industry on March 8, 2024 under Project 2020-06. This will ensure accuracy and consistency across all 3 Standard Projects regarding Facilities Applicability and IBRs.	
Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	
DT removed footnote 1. The DT is utilizing the glossary term of IBR.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation agrees with both the NAGF and EEI additional comments for PRC-030-1. Those comments are as follows: NAGF provided the following comments: *For Requirement 2, the NAGF notes that any IBR data request initiated by the Reliability Coordinator (RC), Balancing Authority (BA), and/or the Transmission Operator (TOP) should be contained in its respective data request processes under IRO-010 & TOP-003. Requirement 2.1.2: The NAGF recommends that this requirement should be included as part of the process created in Requirement R1. In addition, the NAGF is concerned with the potential for overlap with PRC-029.* *Requirement R3: The NAGF seeks clarification as to why the Generator Owner must provide a CAP or technical justification to the RC, BA, and TOP.*	

Requirement R4.3: The NAGF recommends that the DT consider removing the requirement to notify the applicable Reliability Coordinator if CAP actions or timetables change and when the CAP is completed. To the extent the RC wants this information, they should request it under their data specification under IRO-010.

EEI - General Comment: Throughout this Reliability Standard there is use of non-glossary terms where glossary terms are available and should be used. (e.g., active power vs. Real Power) While in other cases glossary terms are used but not capitalized. (e.g., reactive power vs. Reactive Power) Greater efforts should be made to use NERC Glossary terms where appropriate and capitalize those terms, as required.

Applicability Section Comments:

Footnote 1: EEI does not support Footnote 1 because it expands the definition of IBRs beyond what was recently approved by the industry, noting the footnotes expansions the definition of IBR to include VSC-HVDC. Furthermore, there was no technical justification for adding VSC-HVDC and the SAR did not include adding VSC-HVDC systems to this project. For this reason, we ask that the definition of IBR not be expanded through footnotes and suggest that the DT submit a technical justification for adding VSC-HVDC systems to the applicability section of this Standard, rather than redefining an approved definition in a footnote.

To address our concerns related to Footnote 1 we suggest that if VSC-HVDC systems are to be classified as IBRs, then the approved definition should be pulled by NERC and resubmitted with those resources added to the definition and resubmitted to the industry for approval. Alternatively, VSC-HVDC systems could be defined separately, and that definition submitted to the industry for approval. In both cases, a technical justification should be submitted to the industry that defines the issues and risks to BPS reliability that VSC-HVDC systems pose. Lastly, this project has been aligned with FERC Order 901, noting that IBR related performance requirements for ride -through are to be completed and submitted to FERC by Nov. 4th. Yet, the DT expands the definition of IBRs by adding VSC-HVDC systems complicating industry approval without any technical justification for expanding the definition.

Requirements Comments:

Requirements R2 & R3: EEI is concerned with the inclusion of requirements that are not clearly defined or sent from multiple registered entities (i.e., RC, BA or TOP). This creates regulatory confusion and places IBR-GOs in a position where they may need to comply with any number of entities without clearly defining who is actually responsible. (See Requirement R2) Moreover, the identification of multiple entities, who could be responsible, creates a situation where IBR-GOs will have reporting obligations to multiple entities because no single entity is identified as being responsible. (See requirement R3) We further note that none of the entities identified (i.e., RC, BA, or TOP) are identified within the Applicability section of this proposed Reliability Standard. Yet, all of this places considerable compliance burdens on the IBR-GOs who will need to analyze and resolve (R2) those issues at the request of any of these entities and provide notification regarding CAP or technical justification, regarding their inability to fully resolve the issues, without any of these entities having clearly defined responsibilities within this standard.

Requirement R4, Subpart 4.3: EEI suggests adding "Upon Request" to Subpart 4.3 for consistency with Requirement R2, Subpart 2.2 because there should not be a regulatory requirement to notify the RC regarding CAP actions, timetables change and when the CAP is completed, unless the RC specifically requests that the GO provide such notification.

Likes 0	
Dislikes 0	

Response

See response to NAGF and EEI comments.

Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

Alignment with FERC Directive for IBR Registration

BPS-connected/non-BES IBRs should be applicable to this standard, as it aligns with the FERC order activities and the on-going NERC Registration effort to incorporate the non-registered BPS-connected IBRs that are owned/operated by the new proposed Category 2 GO and GOP entities. Exclusion of these BPS-connected resources would significantly limit the ability to ensure that all BPS-connected IBRs have adequate voltage and frequency ride-through requirements during BPS/BES disturbances.

Alignment with NERC Glossary Definitions for IBRs

It does not appear that the text of footnote 1 aligns with the body text for the term “inverter-based resources (IBR)”. That footnote text should be updated accordingly to match the intended definition. However, creating a new definition for “inverter-based resources” for this standard (and PRC-028 and PRC-029) is not aligned with the on-going IBR standard related work throughout NERC. By creating a new definition, it seems counter-productive to have a unique definition of IBRs and IBR units under the different NERC standards. Having all standards aligned to the new core NERC Glossary definition for IBRs will make all this standard development work, execution of the standards, and compliance activities more efficient for all entities involved.

Likes 0	
Dislikes 0	

Response
DT has revised applicability section to clarify in scope facilities. DT removed footnote 1. DT capture and updated appropriate NERC Glossary Defined terms.
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	
Document Name	

Comment
The definition for Inverter Based Resource (IBR) was approved by industry in April under Project 2020-06. We do not agree with inserting the uncapitalized version of IBR into 4.2 Facilities section because it is unbounded and insufficient to identify the Facilities applicable to this Standard, as required in the Rules of Procedure (Appendix 3a, Standard Processes Manual). Furthermore, these definitions are the foundation of several ongoing projects in response to FERC Order 901, where FERC “directs NERC to submit new or modified Reliability Standards that address specific matters pertaining to the impacts of IBRs on the reliable operation of the BPS.”

It is imperative that the standard drafting teams for this project as well as the 2021-04 (PRC-002 and PRC-028) and 2020-02 (PRC-029 and PRC-024) assure a coherent way of addressing the inclusion and exclusion of IBRs in current and upcoming standards. These three different projects have all used different ways of drafting up section 4.2 of the standard.

The following comments are specific to PRC-030-1, Requirement R1 :

· Add an exclusion for active power changes linked to frequency regulation and power limitations/runback ordered by the TO.

· Add an exclusion for faults inside the IBR plant.

Likes 0	
Dislikes 0	

Response

DT has adopted the IBR glossary term.

DT incorporated suggested R1 additions to exclusions.

Ruchi Shah - AES - AES Corporation - 5

Answer	
Document Name	

Comment

Some criteria should be added to the RA/BA/TOP request for analysis under R2. AES CE does not believe that an analysis for changes below the thresholds in R1 should be included in the requirement, even if requested by the RA/BA/TOP.

Likes 0	
Dislikes 0	

Response

R1 was designed to capture most performance issues however it was not possible to capture all performance issues. R2 is necessary to allow RC, BA, or TOP to initiate investigations for larger system distubances or performance issues that may not meet R1 threholds.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
Tri-State supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
See response to MRO NSRF comments	
Brian Lindsey - Entergy - 1	
Answer	
Document Name	
Comment	
R2. Data quality concern in an event happening in 4 seconds and being able to complete the analysis. Concerns with having to provide the information to multiple entities. R3 and R4: Have a concern with multiple entities requesting information and a single POC would be more efficient. Should be no need to provide CAP to other entities unless explicitly requested.	

The action to create the Corrective Action Plan should 90 days instead of 60 days. Recommend adding language in R3 that states that if all actions are completed during the analysis phase to correct the issue there will be no need for a CAP.	
Likes 0	
Dislikes 0	
Response	
The DT recognizes the GO may have limited data to analyze events until PRC-028 is fully implemented. The GO should use the best available information at the time of the event. RC, BA, and TOP have the responsibility for reliability and hence the need-to-know performance issues and CAPs associated with such issues. DT determined to leave development of the CAP to 60 days. CAP still should be documented.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	
Document Name	
Comment	
AZPS supports the following comments that were submitted by EEI on behalf of its members: EEI offers the following suggested changes to PRC-030-1: General Comment: Throughout this Reliability Standard there is use of non-glossary terms where glossary terms are available and should be used. (e.g., active power vs. Real Power) While in other cases glossary terms are used but not capitalized. (e.g., reactive power vs. Reactive Power) Greater efforts should be made to use NERC Glossary terms where appropriate and capitalize those terms, as required. **Applicability Section Comments:** Footnote 1: EEI does not support Footnote 1 because it expands the definition of IBRs beyond what was recently approved by the industry, noting the footnotes expansions the definition of IBR to include VSC-HVDC. Furthermore, there was no technical justification for	

adding VSC-HVDC and the SAR did not include adding VSC-HVDC systems to this project. For this reason, we ask that the definition of IBR not be expanded through footnotes and suggest that the DT submit a technical justification for adding VSC-HVDC systems to the applicability section of this Standard, rather than redefining an approved definition in a footnote. To address our concerns related to Footnote 1 we suggest that if VSC-HVDC systems are to be classified as IBRs, then the approved definition should be pulled by NERC and resubmitted with those resources added to the definition and resubmitted to the industry for approval. Alternatively, VSC-HVDC systems could be defined separately, and that definition submitted to the industry for approval. In both cases, a technical justification should be submitted to the industry that defines the issues and risks to BPS reliability that VSC-HVDC systems pose. Lastly, this project has been aligned with FERC Order 901, noting that IBR related performance requirements for ride -through are to be completed and submitted to FERC by Nov. 4th. Yet, the DT expands the definition of IBRs by adding VSC-HVDC systems complicating industry approval without any technical justification for expanding the definition. **Requirements Comments:** **Requirements R2 & R3:** EEI is concerned with the inclusion of requirements that are not clearly defined or sent from multiple registered entities (i.e., TP, PC, RC, or TOP). This creates regulatory confusion and places IBR-GOs in a position where they may need to comply with any number of entities without clearly defining who is responsible. (See Requirement R2) Moreover, the identification of multiple entities, who could be responsible, creates a situation where IBR-GOs will have reporting obligations to multiple entities because no single entity is identified as being responsible. (See requirement R3) We further note that none of the entities identified (i.e., TP, PC, RC, or TOP) are identified within the Applicability section of this proposed Reliability Standard. All of this places considerable burden on the IBR-GOs that needs to be resolved and clarified. **Requirement R4, Subpart 4.3:** EEI suggests adding “Upon Request” to Subpart 4.3 for consistency with Requirement R2, Subpart 2.2 because there should not be a regulatory requirement to notify the RC regarding CAP actions, timetables change and when the CAP is completed, unless the RC specifically requests that the GO provide such notification.

Likes 0	
Dislikes 0	
Response	

See response to EEI comments.	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
Constellation supports NAGF comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
See response to NAGF comments.	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
Constellation supports NAGF comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	

Response	
See response to NAGF comments.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
R3 currently reads "… develop one of the following and provide it to the applicable Reliability Coordinator, Balancing Authority, *and* Transmission Operator." Shouldn't this say "…Reliability Coordinator, Balancing Authority, *or* Transmission Operator"? (Same with M3.) R4.3 should also require notification "to each the applicable Reliability Coordinator, Balancing Authority, or Transmission Operator" rather than only to the Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	
RC, BA, and TOP have the responsibility for reliability and hence the need-to-know performance issues and CAPs associated with such issues. RC has ultimate responsibility for reliability and hence the need to know once the CAP is implemented.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	

FirstEnergy believes that the request for information to and from an IBR Owner may require a full 120 days similar to PRC-004 (understanding IBR's are excluded from PRC-004). We therefore are asking the DT to consider matching the timeframe for PRC-030 with that of PRC-004. This would also provide consistency throughout the industry and eliminate confusion between these two standards. We also suggest that the third criteria under R1 be changed from “Transmission Provider’s” to “Transmission Service Provider” noting that Transmission Provider is not a defined term in the NERC Glossary.	
Likes 0	
Dislikes 0	
Response	
The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes. DT has made changes to R1 exclusion list.	
Thomas Foltz - AEP – 5	
Answer	
Document Name	
Comment	
As AEP stated in the previous ballot period, the scope and general intent of PRC-030 appears reasonable, but the process and flow are flawed and needs to be changed. While it might be reasonable to simply identify the “event” within 90 days (or 120 days to match PRC-004), additional time will still be needed to research and determine the root cause(s). This could conceivably take 90 days or more, especially if support is needed from the OEM. And once the cause is determined, at least 60 additional days (to match PRC-004) would then be needed to develop the CAP and document the Applicability (R2.1.2) of that CAP to other facilities. Applicability cannot be documented without first determining the root cause and then possibly developing the CAP. It cannot be assumed that a root cause will be found in every case, and the standard needs to allow for this. To further illustrate our concern, the standard drafting team provided this response to AEP comments: “The Drafting Team believes it should be up to the GO to develop a process to identify and analyze events. Requirement R2 makes it clear that they have 90 days from the date of the event to complete analysis, regardless of when the	

event was identified. They also have 90 days to complete analysis of events identified by the BA, RC, or TOP from the date they were notified of the event.” AEP understands this response, however the revisions to the standard do not match this response. Specifically, “that they have 90 days from the date of the event” is not what is written in R2. R2 presently reads “within 90 calendar days of identifying an active power change event”, which has a different meaning. AEP agrees that it should be measured from the date of the event, not the date of identifying an event. One related gap, as we see it, is that it is not explicitly clear how many days are afforded to identify an event, though 90 days are inferred. These collective concerns are the primary driver behind our decision to vote negative on PRC-030.

The proposed version of PRC-030 makes the assumption that a root cause will be found in every case, but this is not realistic. The standard must be revised to accommodate for situations where a root cause(s) is never found or identified.

AEP would like to see the timelines align with those used in PRC-004, where appropriate.

It might be advantageous for a flowchart to be added to the Technical Rationale document. In that light, AEP reads the present structure for R2/R3 as follows:

After R2 Event identification date or Event Notification date occurs, will within 90 days perform the following:
1) Determine root cause of change in power output
2) Document plant ride-through performance for the event
3) Assessment of any performance issues and if any corrective actions are needed
4) Determine susceptibility of other IBRs to similar events (applicability)
After these are accomplished, then proceed to R3 obligations to develop CAP or make No CAP declaration.

In addition, AEP would prefer the proposed structure for R2/R3 to be as follows:
R2:
1) Event date or Event Notification starts process to complete the following within 120 days of the Event or within 60 days of Event Notification, whichever is later
a) Document plant ride-through performance for the event and
b) Assessment of any performance issues and if any corrective actions are needed
2) R3: Once the Root Cause is found/identified, the following must be accomplished within 60 days:
a) Determine susceptibility of other IBRs to similar events (applicability)

b) Develop CAP or make a No CAP Declaration The new footnote 1 is problematic, as it does not appear to correlate with the IBR. We believe its inclusion may have been unintentional. R2 and R3 include the word “applicable” when referencing the RC, BA, and Transmission Operator, however we believe this word is misleading and may be interpreted inconsistently. As a result, we recommend removing this word from R2 and R3.	
Likes 0	
Dislikes 0	
Response	
The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes. The DT’s intent was that the GO review and identification of R1 events would occur in a timely fashion. The DT decided to align the 90-day analysis period for both self-identified events (R1) and RC, BA, or TOP identified events (R2). If no root cause is found, a GO should work with the RC to explain the details of the performance issues and develop a monitoring plan to capture future events. Figure 1.1 and Figure 1.2 of the TR includes a flowchart illustrating the intended process for PRC-030. The DT discussed changing the time, however had decided to stick with performing an analysis within 90 days of event identification and 60 days for CAP development. The DT removed Footnote 1. The DT believe applicable in the case of R2 and R3 is a necessary qualifier to determine which RC, BA, or TOP is involved.	
Bruce Walkup - Arkansas Electric Cooperative Corporation – 6	
Answer	

Document Name	
Comment	
R2 and R3 should allow for extended time periods for analysis and implementation. The quantity of events triggers R1 will create and require to be looked at is going to be staggering and if an update is required, the time required to implement them in a large-scale plant could be hard to meet.	
Likes 0	
Dislikes 0	
Response	
The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes.	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	
Document Name	
Comment	
SMEs responded with the following "R2 and R3 should allow for extended time periods for analysis and implementation. The quantity of events triggers R1 will create and require to be looked at is going to be staggering and if an update is required, the time required to implement them in a large-scale plant could be hard to meet."	
Likes 0	
Dislikes 0	
Response	
The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes.	

Kevin Conway - Western Power Pool - 4

Answer	
Document Name	
Comment	
The Drafting Team has a challenging task of meeting a FERC directive, yet creating a standard that is acceptable to the affected entities. It is in the best interest of the industry to focus on performance metrics, and not administrative compliance for ensuring there are processes and plans. This has the added advantage of allowing each entity to implement the best solutions for their unique needs.	
Likes 0	
Dislikes 0	
Response	
Performance metrics are being developed under PRC-029.	

End of Report