Comment Report

Project Name:	2020-02 Modifications to PRC-024 (Generator Ride-through) | Draft 1
Comment Period Start Date:	3/27/2024
Comment Period End Date:	4/22/2024
Associated Ballots:	2020-02 Modifications to PRC-024 (Generator Ride-through) Implementation Plan IN 1 OT 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-024-4 | Non-binding Poll IN 1 NB 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-024-4 IN 1 ST 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-029-1 | Non-binding Poll IN 1 NB 2020-02 Modifications to PRC-024 (Generator Ride-through) PRC-029-1 IN 1 ST

There were 79 sets of responses, including comments from approximately 180 different people from approximately 111 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the need for creating a new Standard (PRC-029-1) to address gaps the Inverter-Based Resource Performance Subcommittee (IRPSC) identified within the PRC-024-3 Project 2020-02 SAR and to address the expectations of FERC Order No. 901?

2. Do you agree that the language within PRC-029-1 requirements R1, R2, and R6 regarding IBR plant-level performance during grid voltage disturbances is clear?

3. Do you agree with the drafting team's proposals for including IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in PRC-029-1 Requirements R3, R4, and R5?

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
Santee Cooper	Carey Salisbury	1,3,5,6		Santee Cooper	Lachelle Brooks	Santee Cooper	1,3,5,6	SERC
					Paul Camilletti	Santee Cooper	1,3,5,6	SERC
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
Southern Company - Southern Company Services, Inc.	Colby Galloway	1,3,5,6	MRO,RF,SERC,Texas RE,WECC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC

					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
California ISO	Darcy O'Connell	2	WECC	ISO/RTO Council (IRC) Standards Review Committee	Ali Miremadi	California ISO	2	WECC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Helen Lainis	Independent Electricity System Operator	2	NPCC
					Elizabeth Davis	PJM Interconnection	2	RF
					Charles Yeung	Southwest Power Pool, Inc.	2	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
Austin Energy	Imane Mrini	6		Austin Energy	Imane Mrini	Austin Energy	6	Texas RE
					Michael Dillard	Austin Energy	5	Texas RE
					Lovita Griffin	Austin Energy	3	Texas RE
					Tony Hua	Austin Energy	4	Texas RE
					Thomas Standifur	Austin Energy	1	Texas RE
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC

					John Nierenberg	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	SERC
					Sara Orr	Golden Spread Electric Cooperative, Inc.	5	Texas RE
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF

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

					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					David Kwan	Ontario Power Generation	4	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Chantal Mazza	Hydro Quebec	1,2	NPCC

					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Chantal Mazza	Hydro Quebec	1,2	NPCC
					Nicolas Turcotte	Hydro-Quebec (HQ)	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Joel Charlebois	AESI	7	NPCC
Elevate Energy Consulting	Ryan Quint	NA - Not Applicable	NA - Not Applicable	Elevate Energy Consulting	Ryan Quint	Elevate Energy Consulting		NA - Not Applicable
					N/A	N/A		NA - Not Applicable
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Stephen Whaite	Stephen Whaite		RF	ReliabilityFirst Ballot Body Member and Proxies	Lindsey Mannion	ReliabilityFirst	10	RF
					Stephen Whaite	ReliabilityFirst	10	RF
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC

					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Gary Dollins	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Olivia Olson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	SERC
					Heath Henry	NW Electric Power	3	SERC

						Cooperative, Inc.		
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	KAMO Electric Cooperative	1	SERC
					Brett Douglas	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Mark Riley	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Chuck Booth	Associated Electric Cooperative, Inc.	5	SERC
					Jarrod Murdaugh	Sho-Me Power Electric Cooperative	3	SERC

1. Do you agree with the need for creating a new Standard (PRC-029-1) to address gaps the Inverter-Based Resource Performance Subcommittee (IRPSC) identified within the PRC-024-3 Project 2020-02 SAR and to address the expectations of FERC Order No. 901?

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
We recommend adding these IBR related requirements to PRC-024, rather than creating a new Standard.	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation does not agree with creating a new IBR specific standard (PRC-29) to address the gaps in the Inverter-Based Resource. While Constellation recognizes that there has been some grid disturbance in the Odessa/California/Utah regions in the past couple years as a result of some IBRs not performing as intended, the creation of a new standard is a quick reaction without ensuring existing equipment's are capable to fully comply. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE supports creating a new standard to address Inverter-Based Resources (IBR) gaps identified. Texas RE is concerned, however, with the structure of the standard as it is presently proposed.

As currently drafted, the proposed PRC-029-1 would wholly eliminate existing frequency and voltage protection setting verification requirements for IBR resources. Texas RE submits that this is contrary to FERC's intent in directing NERC to develop a comprehensive ride-through standard for IBR resources. FERC Order No. 901 explicitly directs NERC to draft a standard "that require[s] IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system excursions and that permit IBR tripping only to protect IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults." (Order No, 901, paragraph 190). FERC's intent behind the order was to expand the scope of applicable devices beyond protection system equipment subject to the current PRC-024 requirements to embrace a range of devices that can trip an IBR facility (inverters, plant controller, etc.). The ultimate goal is to better ensure that IBRs provide reliable performance during voltage and frequency excursions.

Texas RE submits, however, that FERC did not intent to exclude IBR entities from the existing verification processes or significant limit the ability of the ERO to review protection system settings prior to an actual disturbance event. In its order, FERC specifically referenced the 2021 Odessa Disturbance Report jointly prepared by NERC and Texas RE staff ("2021 Odessa Disturbance Report"). The 2021 Odessa Disturbance Report in turn called for the development of a ride-through standard to replace PRC-024-3 because "the events analyzed by NERC regarding fault-induced reductions in solar PV output and wind output have identified issues with controls and protections unrelated to voltage and frequency." (2021 Odessa Report, at 29). While calling for a more comprehensive standard, however, the report simultaneously identified pervasive issues with protection system settings within the scope of the current PRC-024 standards. The report noted: "Numerous plant owner/operators have stated that they do not have sufficient technical staff on hand to interpret the results and will simply install what the consultant recommends. This is leading to poorly coordinated protection systems within the facility, causing unreliable performance from BPS-connected solar PV facilities in multiple interconnections." (2021 Odessa Report, at 17 (emphasis added)). In short, while acknowledging that the current PRC-024 standard is overly narrow, FERC and the various reports FERC references make clear that protection system verification failures remain an important contributing factor in the numerous disturbance events involving IBRs over the past few years.

As proposed, PRC-029-1 would result in a reliability gap by requiring that protection system settings no longer require verification. The Standard Drafting Team (SDT) explains in the draft PRC-029-1 Technical Rationale that "[a]n IBR becomes noncompliant with PRC-029 only when an event in the field occurs that shows that one or more requirements were not satisfied." Under the SDT's proposed approach, therefore, the existing PRC-024 protection system setting verification requirements would be eliminated and the sole mechanism to verify performance would be an IBR's failure to perform during a disturbance event. Texas RE posits that this approach is inconsistent with the intent of FERC's order to expand the applicable devices and settings that an IBR-entity must ensure are properly set to avoid unnecessary tripping during events. It is also inconsistent with findings that entities continue to experience issues properly setting (and verifying) existing protection systems within the scope of the current PRC-024 requirements.

Rather than pursue this approach, Texas RE suggests that the SDT consider retaining the existing protection system verification requirements as a foundational step, but augment those requirements with a general performance standard. Moreover, while Texas RE does not believe the SDT needs or should develop a comprehensive and prescriptive list of devices that must be appropriate set and coordinated to ensure IBR performance, the SDT should consider which measures and evidence would be appropriate for the GO and TO to demonstrate that its settings meet the various no-trip zone parameters described in Attachment 1. This should include sufficient evidence to show that protection system settings are properly set to not trip within appropriate no trip zones, as well as that other settings for inverters, plant controllers, and other devices are properly coordinated. Such clarity will ensure that at least minimum performance can be audited and verified prior to a disturbance event – the goal of the standards process.

Additionally, Texas RE noticed during the webinar, SDT stated that the requirements do not apply to individual IBR units. Requirement R1 seems to indicate that each IBR unit needs to remain electrically connected and continue to exchange current in accordance with the no-trip zones and operation regions.

Lastly, Texas RE recommends the SDT consider changing 'each IBR' to 'each IBR Facility' for all the Requirements.

Likes 0	
Dislikes 0	

Response

Joy Brake - Nova Scotia Power Inc. - NA - Not Applicable - NPCC

Answer	No
Document Name	

Comment

A performance standard should be based on function not technology type which is always changing. An IBR generation facility should meet the same performance threshold as traditional generation, with additional support devices as necessary incorporated into the facility design to meet the same level of performance as a traditional unit.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

PRC-024-3 has not been in effect long enough to be deemed inadequate to address "gaps" and issues described in IBR disturbance reports. It became effective on 10/1/2022, which was long after major disturbances occurred, and as written, covers major causes of IBR disturbances such as voltage, frequency, and momentary cessation. Most importantly, the Standard clearly stated applicability to individual IBR units and it clearly stated no-trip zones. The Standard could have been modified to include and cover other recommendations from the disturbance report such as PLL protection and ramp rate mis-coordination.

Likes 0	

Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	No
Document Name	

Comment

Constellation does not agree with creating a new IBR specific standard (PRC-29) to address the gaps in the Inverter-Based Resource. While Constellation recognizes that there has been some grid disturbance in the Odessa/California/Utah regions in the past couple years as a result of some IBRs not performing as intended, the creation of a new standard is a quick reaction without ensuring existing equipment's are capable to fully comply.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Michael Goggin - Grid Strategies LLC - 5

Answer	No
Document Name	

Comment

A major concern with the separate Standards, as drafted, is that ride through performance is not required for synchronous generators under PRC-024-4, but it is for IBRs under PRC-029. PRC-02-4 simply requires protective relays to be set so they do not trip the generator within specified bounds, but it allows a resource to trip offline for other reasons. PRC-024-4 also allows a plant to trip if protection systems trip auxiliary plant equipment, per section 4.2.3. In contrast, PRC-029 requires IBRs to remain electrically connected and to continue to exchange current within the specified voltage and frequency bounds. Said another way, an IBR and a synchronous resource could both trip during the same disturbance, and the IBR would be in violation of PRC-029 but the synchronous generator would not be in violation of PRC-024-4, as long as the synchronous generator did not trip due to the settings of its protection system.

To ensure grid reliability and resilience, all resources including IBRs and synchronous resources should ride through grid disturbances. The failure of synchronous generators to ride through grid disturbances threatens grid reliability as much or more than the failure of IBRs, as synchronous resources are often producing at a higher level of output, are more typically relied on as capacity resources, and often take longer to come back online and ramp up to full output if they trip due to a disturbance.

FERC Order 901 directed NERC to treat IBR resources similarly to how NERC Standards treat synchronous generators, writing that the IBR Standard should “permit IBR tripping only to protect the IBR equipment in scenarios similar to when synchronous generation resources use tripping as protection from internal faults."{C}[1] Allowing synchronous generators to trip but requiring IBRs to ride through the same or similar disturbance could be challenged at FERC as undue discrimination.

Not requiring ride-through performance from synchronous generators is also at odds with the intent for this project that NERC stated in its February 2023 comments on the FERC proposed rulemaking that led to Order 901: "A comprehensive, performance-based ride-through standard is needed to assure future grid reliability. To that end, NERC re-scoped an existing project, Project 2020-02 Modifications to PRC-024 (Generator Ride-through), to revise or replace current Reliability Standard PRC-024- 3 with a standard that will require ride-through performance from all generating resources."[2] FERC's Order 901 also noted NERC's statement that this project would require ride-through performance from all generating resources,[3] so a failure to require ride-through performance from synchronous generators may be contrary to both NERC and FERC's intent.

The drafting team should make PRC-024-4 a ride-through performance requirement like PRC-029, or alternatively create a single standard that applies to both types of resources (with any necessary clarifications or minor differences in requirements to reflect the differences in IBR and synchronous generator technologies).

{C}[1]{C} Order 901, https://www.ferc.gov/media/e-1-rm22-12-000, at paragraph 190

{C}[2]{C}https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Comments_IBR%20Standards%20NOPR.pdf, at 21-22

{C}[3]{C} Order 901, https://www.ferc.gov/media/e-1-rm22-12-000, at paragraph 185

Likes 0	
Dislikes 0	
Response	
Carey Salisbury - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Campbell - David Campbell On Behalf of: Natalie Johnson, Enel Green Power, 5; - David Campbell	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
While AEP agrees with creating PRC-029-1 to address the identified gaps, AEP recommends the SDTs for PRC-028, PRC-029 and PRC-030 review each proposed standard obligations to ensure there is a consistent, integrated plan across these projects and standards to achieve the goal of correcting the past performance of Invertor-Based Resources and IBR units. Having a coherent strategy document that explains how these three standards complement each other (and not be duplicative) would be beneficial.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Synchronous generation and Inverter-based resources should have separate standards due to their unique differences. Presently, behavior of Synchronous generation during disturbances and faults is very well understood compared to IBR technology.	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	IESO Comments for PRC-024 PRC-029 Draft 1.docx
Comment	

Complete set of comments for all Qs attached in file: IESO Comments for PRC-024 and PRC-029 Draft 1

Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	

Response

Brian Lindsey - Entergy - 1

Answer	Yes
Document Name	

Comment

Yes, we need a separate a standard. The technologies are different enough that a separate standard will reduce confusion.

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	Yes
Document Name	

Comment

AECI supports comments provided by the NAGF

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

FirstEnergy supports the need for the new standard (PRC-029-1).

In addition, FE supports EEI's comments which state:

EEI agrees with most of the proposed language in Requirements R1, R2 and R6; however, the phrase "of an applicable IBR" should be removed. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant.

Additionally, Requirement R2, subpart 2.5 could be understood to mean that IBRs whenever the voltage at the high-side of the main power transformer is within the no-trip zone, as specified in Attachment 1, must not trip even if it might lead to equipment damage. We offer the following proposed edits in boldface to Requirement R2, subpart 2.5 to clarify the requirement. NERC Reliability Standards should never mandate that equipment run to failure.

2.5 **Each IBR shall only trip to prevent equipment damage, W**hen**ever** the voltage at the high-side of the main power transformer is within **of** the no-trip zone, as specified in Attachment 1, **each IBR shall continue to operate except when the continued operation of the IBR would lead to equipment damage**.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	Yes
Document Name	

Comment

Black Hills Corporation agrees that there is a gap in PRC-024-3 regarding performance of inverter-based resources (IBR). However, more consideration should be given to creating "protection-based" Standards for IBR, whether as an update to existing Standard PRC-024-3 or new Standard PRC-029-1 rather than the "event-based" approach currently being taken in PRC-029-1.

Likes 0	
Dislikes 0	

Response

Stefanie Burke - Portland General Electric Co. - 6

Answer	Yes
Document Name	

Comment

PGE requests that the Standard Drafting Team (SDT) add clarity regarding Attachment A: Voltage Boundary Clarifications, Section: Evaluating Protection Settings, a. The most probable real and reactive loading conditions for the unit under study.

Loading conditions vary depending on the type of unit, location, time of year, etc. How should an entity assess “most probable” loading conditions? Are entities being required to account for the worst case scenarios providing the greatest voltage change(s), not just a probable condition that may represent little to no significant voltage difference?

PGE also notes that the Table References and Figure References are not aligned

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	Yes
Document Name	

Comment

Yes, the technological differences warrant separate standards for IBRs and synchronous generation.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 1,3,6

Answer	Yes
Document Name	

Comment

Ameren agrees with EEI's comments.

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5

Answer	Yes
Document Name	

Comment

Yes, the technological differences warrant separate standards for IBRs and synchronous generation.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Duke Energy recommends the implementation of EEI comments.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

EEI supports the development of a new Reliability Standard to address gaps in Inverter-Based Resource Performance and while the SAR does not include any language that specifically addresses FERC Order No. 901, EEI has no concerns with the SDT adjusting PRC-029 in line with the directives contained in this Order.	
Likes 0	
Dislikes 0	
Response	
Imane Mrini - Austin Energy - 6, Group Name Austin Energy	
Answer	Yes
Document Name	
Comment	
AE supports comments provided by Texas RE and the NAGF	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Maozhong Gong - GE - GE Wind - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

But we have additional comments.

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	Yes
Document Name	

Comment

SRP believes that there is a huge lack of oversight in regard to inverter-based resources. Regulation on IBR controls is somewhat late but we are glad is happening.

Likes 0	
Dislikes 0	

Response

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers

Answer	Yes
Document Name	

Comment

Vistra agrees with AEP.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	Yes
Document Name	

Comment

OPG supports IESO's comments.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

Southern Company believes that separating synchronous machine facilities from IBR facilities simplifies the complication that would exist by addressing both types of facilities in the same standard. While the existing "legacy" facilities have demonstrated imperfect ride-through performance (reactions) during system initiated disturbances, Southern believes that the application of ride-through requirements should only be applicable to facilities designed, built, and commissioned after the development of such a standard. The existing "legacy" facilities were not designed or built to achieve the desired ride-through performance that is specified in PRC-029-1, requirements R1-R5 of this proposed standard, and should not be subject to those requirements. The demonstrated performance, while not matching the ideal performance dictated by this proposed standard, is not catastrophic to the interconnection. The notion that generator owners have not taken any actions to improve the reaction of the legacy facilities to system disturbances is false. Southern Company has reviewed and modified control and protection settings for inverter operations at multiple facilities since the issuance of the first two NERC Alerts on the Loss of Solar facilities and during the multiple disturbance analysis evaluations. Addressing the desired performance with new facilities which will have the component design and control strategies sufficient to meet the desired performance should be a measure adequate to address the frequency control, voltage control, and stability needs and concerns of the interconnection.

Perhaps a more reasonable approach towards achieving better IBR facility ride through performance during system disturbance events, is to require evaluations with every instance of a plant output hiccup. The proposed required evaluation process in PRC-030, requiring corrective action plans to minimize/eliminate/eradicate the reason for the hiccup, would address, where possible, action taken through control or protection system setting changes, or through hardware changes - for equipment placed in service after the effective date of this draft standard).

Southern would offer general concerns with synchronizing language across all draft standards. For example, M1 states: *"shall have evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements"*. This seems like an opportunity to clarify by explicitly referencing standard(s) addressing data collection. This example repeats in some form in each "M" paragraph. Should the evidence of actual recorded data in M1 and other measures synch up with the phased in approach to PRC-028?

Finally, Southern Company supports EEI and NAGF comments.

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	Yes
Document Name	

Comment

NextEra aligns with EEI's comments:

EEI supports the development of a new Reliability Standard to address gaps in Inverter-Based Resource Performance and while the SAR does not include any language that specifically addresses FERC Order No. 901, EEI has no concerns with the SDT adjusting PRC-029 in line with the directives contained in this Order.

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	Yes
Document Name	

Comment

PG&E agrees with creating the new Standard PRC-029-1 to address IBRs.

Likes 0	

Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI comments	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Thank you for leaning heavily on IEEE 2800.	
Likes 0	
Dislikes 0	
Response	
Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting	
Answer	Yes
Document Name	
Comment	
Yes, generator ride-through is an essential reliability service and the changing generation technology to inverter-based has led to the need for improved, applicable, appropriate, and technically accurate requirements that suit IBRs. However, it is critically important that the implementation of these requirements consider all stakeholder needs and capture important technical considerations so that the requirements sufficiently mitigate risks without causing unnecessary costs or burdens on any responsible entity.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Brytowski - Great River Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brittany Millard - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Shonda McCain - Omaha Public Power District - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katrina Lyons - Georgia System Operations Corporation - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darcy O'Connell - California ISO - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Wesley Yeomans - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	2020-02_EPRI Comments on Draft NERC PRC-029 (IBR ride-through) Reliability Standard.pdf
Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you agree that the language within PRC-029-1 requirements R1, R2, and R6 regarding IBR plant-level performance during grid voltage disturbances is clear?

Darcy O'Connell - California ISO - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee	
Answer	No
Document Name	

Comment

The ISO/RTO Council (IRC) Standards Review Committee (SRC) recommends the following modifications to improve the clarity and better convey the intent of the standard.

Recommended changes to R1:

"…as specified in Attachment 1 except when needed to clear a fault or a documented **and communicated** equipment limitation exists in accordance with **Requirement R6."**

Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that each IBR remains electrically connected and continues to exchange current in accordance with the no-trip zones and operation regions as specified in Attachment 1 unless needed to clear a fault or a documented equipment limitation exists in accordance with Requirement R6.

Recommended changes to M1:

"…demonstrating adherence to ride-through requirements, as specified in Requirement R1**, or shall have evidence of a documented and communicated equipment limitation, as specified in Requirement R6**."

Recommended changes to R2:

"…each IBR's voltage performance adheres to the following, unless a documented **and communicated** equipment limitation exists…"

The SRC recommends that the SDT to review and align the data in **Attachment 1** to ensure that the data in Tables 1 and 2 aligns with what is shown in Figures 1 and 2. Currently, the graphs in Figures 1 and 2 do not match what is indicated in the Tables. For example, rows 1-3 in Tables 1 and 2 are identical, yet Figure 2 does not match Figure 1 by indicating a Voltage Ride-Through Requirement of 1.0.

It appears that the SDT's intent is to require continuous operation between 95% and 105% voltage with a minimum ride-through time of at least 1800 seconds (half an hour) when voltage is above 105% and not exceeding 110%. If the intent is actually that equipment must be able to operate *continuously* at voltages up to 110%, then the tables and plots should be labelled with a descriptor that clearly indicates that indefinite or continuous operation is required rather than operation for a minimum ride-through time (1800 seconds). For example, a version of Table 2 that achieves the SDT's apparent intent could look like the following:

Voltage (per unit)	**Minimum Ride-Through Time (sec)**
>1.2	N/A

<=1.2 and >1.1	1.0
<=1.1 and >1.05	1800
<=1.05 and >=0.95	Continuous
<0.95 and >=0.90	Continuous*

*current limitation permitted, with active or reactive power preference as specified

<0.90 and >=0.70	6
<0.70 and >=0.50	3
<0.50 and >=0.25	1.2
<0.25	0.32

While the above comments point out areas of ambiguity in the draft standard that need to be clarified, the SRC recommends that Table 1 and Table 2 be modified to require IBR plants remain connected indefinitely when the voltage is between 1.05 and 1.1 pu. The current draft standard requires units to remain online for 1800 seconds in this range, and the logic behind this threshold is not clear. The current PRC-024 standard requires units to remain on-line indefinitely for the above range. [*All SRC entities support the comments in this paragraph except MISO*].

In addition, the SRC recommends a part be added to the standard to directly address the Permissive Operating Region, similar to what is done in Part 2.1 (for the Continuous Operation Region) and Part 2.2 (for the Mandatory Operation Region) as, the rules surrounding the Permissive Operating Region are unclear if this is not addressed. For example, there should be some linkage between the body of the standard and Attachment 1, item 10. The SRC proposes the following language for consideration (new Part 2.3):

2.3 While voltage at the high-side of the main power transformer is within the Permissive Operation Region as specified in Attachment 1, an IBR may operate in current block mode only if necessary to protect the equipment. Otherwise, each IBR shall follow the requirements for the Mandatory Operation Region in Requirement R2, Part 2.2.

Recommended changes to R6:

The SRC is concerned that Requirement R6 as proposed provides an overly broad exemption, as the standard is silent as to what criteria must be met to qualify for an exemption and contains no requirement that a Corrective Action Plan be developed or that the equipment limitations be resolved or addressed. Only notification to other entities is required. The SRC recommends that the SDT:

- Develop more specific criteria as to what qualifies as an equipment limitation[1], OR A technical justification that addresses why corrective actions will not be applied nor implemented.
- Require exemptions be submitted to NERC and/or the Regional Entities for pre-approval in order to qualify for the exemption.

The SRC suggests there should be explicit requirements to both ‘document equipment limitations’ and to ‘communicate’ those documented limitations to the appropriate parties. The SRC proposes the following modifications to address this issue:

"Each Generator Owner and Transmission Owner with a **known** equipment limitation that would prevent an applicable IBR that is in-service by the effective date of this standard from meeting voltage ride-through requirements as detailed in Requirements R1 and R2 shall **document** each equipment limitation, develop a Corrective Action Plan to address the limitation, **and communicate both the limitation and the Corrective Action Plan** to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s).

Recommended changes to M6:

Each Generator Owner and Transmission Owner shall have evidence of **known** equipment Limitations accompanied by a Corrective Action Plan, as specified in Requirement R6, **having been** documented **and communicated** to each associated Planning Coordinator, Transmission Planner, and Reliability Coordinator prior to the effective date of PRC-029-1.

Each Generator Owner and Transmission Owner with changes to equipment shall have evidence of communication to each associated Planning Coordinator, Transmission Planner, and Reliability Coordinator.

[1] *See Implementation Plan (page 4), "only those IBR that are unable to meet voltage ride-through requirements due to their inability to modify their coordinated protection and control settings may be considered for potential exemption." See Technical Rationale (page 9); i.e. specify which voltage band(s) and associated duration(s) cannot be satisfied or specific as to the number of cumulative voltage deviations within a ten-second time period that the equipment can ride-through if less than four… identify the specific equipment and explain the characteristic(s) of that equipment that prevent ride-through.*

Likes 0	
Dislikes 0	

Response

Michael Brytowski - Great River Energy - 3

Answer	No
Document Name	Attachment 1 figures 1 and 2 .pdf

Comment

Comments: GRE requests the SDT review and align the data in **Attachment 1** so the data in Tables 1 and 2 aligns with what is shownin Figures 1 and 2. Currently, the graphs in Figures 1 and 2 do not match what is indicated in the Tables. (uploaded)

GRE recommends a part be added to the standard to directly address the Permissive Operating Region, similar to what is done in Part 2.1 (for Continuous Operation Region) and Part 2.2 (for Mandatory Operation Region) as, if left unaddressed, is unclear. For example, there should be some linkage between the body of the standard and Attachment 1, item 10. MRO NSRF proposes the following language for consideration (*new* Part 2.3):

2.3 While voltage at the high-side of the main power transformer is within the Permissive Operation Region as specified in Attachment 1, an IBR may operate in current block mode only if necessary to protect the equipment. Otherwise, each IBR shall follow the requirements for the Mandatory Operation Region in Requirement R2.2.

GRE is concerned that requirement R6 provides an overly broad exemption as written as the standard is silent as to what criteria must be met. Only notification to other reliability entities is required with no requirement to develop and implement a Corrective Action Plan. MRO NSRF recommends the SDT:

Develop more specific criteria as to what qualifies as an equipment limitation[1], OR

Require exemptions be submitted to NERC and/or the Regional Entities for approval in order to qualify for the exemption.

[1] *See Implementation Plan (page 4), i.e. "only those IBR that are unable to meet voltage ride-through requirements due to their inability to modify their coordinated protection and control settings may be considered for potential exemption." See Technical Rationale (page 9); i.e. specify which voltage band(s) and associated duration(s) cannot be satisfied or specific as to the number of cumulative voltage deviations within a ten-second time period that the equipment can ride-through if less than four… identify the specific equipment and explain the characteristic(s) of that equipment that prevent ride-through.*

R2: GRE agrees with the present flexibility that some of the IBR VRT performance could be modified to meet the individual system needs by the applicable Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator. However, some clarity may be required on how this process is initiated and what type is evidence is required to demonstrate request is received and implemented. This may be an additional requirement assigned to the Transmission Planner. Each Transmission Planner, Planning Coordinator, and Transmission Operator that jointly specifies the following voltage ride-through performance requirements within their area(s) different than those specified under R2, shall make those requirements available to each associated applicable IBR Generator Owner and Transmission Owner.

Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	No
Document Name	
Comment	
See comments below under question 4.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	

Comment	
R2.5 & R5.1, et al. Each IBR shall only trip … "Trip" may be ambiguous. Does this mean disconnecting from the system to de-energize the IBR equipment, as in opening a circuit breaker? Or does it mean cease exchanging current? Or something else?	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
For R1, We recommend adding language to refer to plants that were previously exchanging current before the disturbance. For example, A BESS that is fully charged would be connected to the BES, but would not be exchanging current. For R2, change "each IBR's voltage performance" to voltage ride through performance. For R6, exemptions should not be automatically allowed. This would allow for bad designs relying on an exemption. Exemptions should only be for existing or legacy units. New units should not have the option for exemption.	
Likes 0	
Dislikes 0	
Response	
Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	No
Document Name	
Comment	
Southwest Power Pool joins the ISO/RTO Council Standards Review Committee comments.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No

Document Name	

Comment

In the opinion of ACES, the newly proposed Glossary Terms are unnecessary and seemingly incongruous terms. For example, if the Mandatory Operating Region is required, should it not also be continuous? It is our opinion that these terms add little to no value and instead only create confusion where none was previously present. We recommend striking these new terms from the standard.

In ACES' opinion, R1 appears to be overly broad so as to require an applicable IBR to be operational at all times. This does not appear to allow for full facility outages without first having a "documented equipment limitation" per R6. Thus, as written, the GO will run the risk of non-compliance with either R1, R6, or both whenever a full facility outage of an IBR is required. Furthermore, it is unclear how R1 differs from R2 other than seeming to requiring the GO to ensure the GOP always keeps the unit online during to normal operation. We recommend striking R1 from the standard.

Additionally, we do not agree with the language of Requirement R2, Part 2.1.1. As written, R2 does not define what type of System disturbance is applicable and Part 2.1.1 requires the GO to continue producing active power at the pre-disturbance levels or its maximum capability; whichever is less. We have concerns with this approach. Namely, during an over frequency deviation event wherein the high side MPT voltage remains ≥ 0.9 p.u. and ≤ 1.1 p.u. In this instance, the frequency response algorithm within the IBR would attempt to reduce active power output. Due to the fast-acting nature of IBRs, it is likely that an IBR facility(ies) would respond to and correct such an event before a synchronous generating resource(s). However, in the aforementioned hypothetical example, to comply with R2.1.1, the IBR frequency response control would need to be either disabled or limited in its response to an over frequency System disturbance. In our opinion, this is not beneficial to the reliability of the BES. While possibly unlikely at the current time, this hypothetical scenario becomes increasingly likely as conventional synchronous generating resources are retired in favor of IBRs.

Furthermore, it is the opinion of ACES that R6 should be modified to include any potential regulatory limitations. This suggested approach is in line with the approach taken in PRC-024-4 R3. We recommend the modifying R6 as follows:

R6. Each Generator Owner and Transmission Owner shall document each known regulatory or equipment limitation that prevents an applicable IBR that is in-service by the effective date of this standard from meeting voltage or frequency ride-through requirements as detailed in Requirements R1 through R5.

6.1 Each Generator Owner and Transmission Owner shall include in its documentation:

6.1.1 Identifying information of the IBR (name, facility #, other)

6.1.2 Which aspects of voltage ride-through requirements that the IBR would be unable to meet

6.1.3 Identify the specific piece(s) of equipment causing the limitation.

6.2 The Generator Owner and Transmission Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner, and Reliability Coordinator within 30 calendar days of any of the following:

6.2.1 Identification of a regulatory or equipment limitation.

6.2.2 Repair of the equipment causing the limitation that removes the limitation.

6.2.3 Replacement of the equipment causing the limitation with equipment that removes the limitation.

Lastly, the values specified in Table 1 and Table 2 in Attachment 1 do not align with the graphs shown in Figure 1 and Figure 2, respectively.

Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	No
Document Name	
Comment	
See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See EEI comments	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

Electric Reliability Council of Texas, Inc. (ERCOT) joins the comments of the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own in addition to the following comments, except to the extent of any specific differences between the SRC comments and the following comments from ERCOT.

As detailed below, the currently proposed language for Requirement R1 is not clear. Additionally, ERCOT believes that plant-level requirements are insufficient because individual IBR unit performance failures continue to occur and could, in aggregate, be just as impactful or more impactful than the complete loss of an IBR plant. The performance threshold should be coordinated with the threshold in PRC-030, and ERCOT believes a reasonable threshold would be the **lesser** of either 20% of the plant's gross nameplate rating, or 20 MW. In an IBR-dominated electric system, these aggregated losses could cause unreliable operations if not corrected. The past 8-10 years have demonstrated that IBR owners will not voluntarily correct these performance issues in the absence of a mandatory reliability standard.

SDT's proposed language (ERCOT finds the bold portions unclear):

"Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that **each IBR** remains electrically connected and continues to exchange current in accordance with the no-trip zones and operation regions as specified in Attachment 1 unless **needed** to clear a fault or a documented equipment limitation exists in accordance with Requirement R6."

ERCOT's proposed language:

"Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that each IBR, **and its IBR units**, remains electrically connected and continues to exchange current in accordance with the no-trip zones and operation regions as specified in Attachment 1 unless **the IBR, or its IBR units, needs to be tripped** to clear a fault or a documented equipment limitation exists in accordance with Requirement R6."

In addition to the concerns with Requirement R1 noted above, ERCOT is concerned that Requirement R2 does not clarify the timeframe encompassed by the term "System disturbance." Without further clarification, "System disturbance" may be interpreted to only describe the fault itself, even though control instability may manifest itself immediately after the fault clears or during the milliseconds or seconds after the fault clears, during which time frequency and voltage support are still critical. While IEEE 2800 defines the disturbance period, and there is an expectation that an IBR will perform acceptably in the continuous operation region, Requirement R2 is not clear that "riding-through" a disturbance includes both the fault and the non-fault portions of the disturbance along with the transition from ride-through mode to a new steady-state (i.e., the post-disturbance period). ERCOT suggests a 10-second window as a bright-line criterion.

SDT's proposed language for Requirement R2.

"R2. Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that during a System disturbance, each IBR's voltage performance adheres to the following, unless a documented equipment limitation exists in accordance with Requirement R6."

ERCOT's proposed language for Requirement R2:

"R2. Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that during, **and up to ten seconds after,** a System disturbance, each IBR's voltage performance **and its associated IBR units'** voltage performance adheres to the following, unless a documented equipment limitation exists in accordance with Requirement R6."

For Requirement R2, Part 2.2.2, ERCOT agrees that location-specific flexibility may be needed and defined by the TP, PC, RC, and or TOP; however, the language should clearly mandate that in such instances, the established performance requirements must also be met. Additionally, the current wording does not address the possibility that reactive current "response" could be in the wrong direction if not properly configured, and the language should be clarified to address this issue. ERCOT proposes the following language for Part 2.2.2 to capture the full spectrum of current priority modes from full aggressive reactive priority mode, to a de-tuned reactive response while in reactive priority mode, to an active priority mode.

"Adjust reactive current injection at the high-side of the main power transformer so that the magnitude of the reactive current **properly** responds to changes in voltage at the high-side of the main power transformer in accordance with default reactive prioritization **or as required by** any applicable Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator **that specifies** a certain magnitude **and timeliness** of reactive power response to voltage changes, **that specifies a maximum allowed active current reduction to provide reactive current, or that specifies** active power priority instead of reactive power priority."

ERCOT also recommends including the following language to help prevent unnecessary misoperations due to the use of unfiltered measurements or instantaneous (no time delay) settings for protection systems, consistent with NERC recommendations for addressing easily preventable performance failures.

R2.2.3 "Utilize sufficient time delays or filtering methods for any voltage measurements utilized by its protection equipment to prevent unnecessary trips due to calculation errors or transients."

ERCOT finds the bolded portions of the SDT's proposed language for Requirement R2, Part 2.3 to be unclear:

"The IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable Attachment 1 Table 1 or Table 2 no-trip zone voltage thresholds and time durations **in its response from** Mandatory or Permissive Operation Regions to the Continuous Operating Region."

ERCOT proposes the following language to clarify the issue:

"The IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable Attachment 1 Table 1 or Table 2 no-trip zone voltage thresholds and time durations **in its response as it transitions from** Mandatory or Permissive Operation Regions to the Continuous Operating Region."

ERCOT would also point out that the last clause may not be necessary because the IBR should not cause high voltage at any time, and the SDT could consider the following alternative language:

"The IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable Attachment 1 Table 1 or Table 2 no-trip zone voltage thresholds and time durations."

Consistent with the comments above on Requirement R2, Part 2.2.2, Requirement R2, Part 2.4 should be revised as follows to clarify that the other requirements or specifications from the RC/PC/TP/TOP must still be met:

"Each IBR shall restore active power output to the pre-disturbance or available level within 1.0 second when the voltage at the high-side of the main power transformer returns to the Continuous Operation Region from the Mandatory Operation Region or Permissive Operation Region (including operation in current block mode) as specified in Attachment 1, **or as required** by any applicable Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator **that specifies** a lower post-disturbance active power level requirement or **that specifies** a different post-disturbance active power restoration time."

Requirement R2, Part 2.5 may not be clear, in light of the new defined terms, that partial trips (including trips of individual IBR units) should not be allowed. While this topic should be coordinated with PRC-030, it goes to the heart of momentary cessation in that staying connected but not supporting frequency and voltage can, in aggregate, be just as detrimental to reliability as a full trip. The SDT should consider revising Part 2.5 to ensure that it is clear that there would be a violation at a particular level (e.g., the lesser of 20% of the unit's rated output, or 20 MW) of IBR unit trips. This could be graduated in severity level starting at the 20% or 20 MW level and increasing thereafter (e.g., 20%, 40%, 60%, 80%, and above).

ERCOT's proposed language for Part 2.5: "Each IBR, **or its IBR units,** shall only trip to prevent equipment damage, when the voltage at the high-side of the main power transformer is outside of the no-trip zone as specified in Attachment 1."

ERCOT also has concerns with the SDT's proposed Requirement R6 language:

"Each Generator Owner and Transmission Owner with **a documented equipment limitation** that would prevent an applicable IBR that is in-service by the effective date of this standard from meeting voltage ride-through requirements as detailed in Requirements R1 and R2 **shall communicate each equipment limitation to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s).**"

More specifically, the first bolded phrase ("a documented equipment limitation") appears to allow complete GO/TO discretion to declare a limitation with no process for review, approval, or acceptance of the limitation by any other entity. Only a communication to the PC, TP, and RC is required. It is unclear if the SDT's intention is that at some point these documented limitations would be reviewed or evaluated under the NERC CMEP (and it is unclear what standard the limitation documentation would be held to under such a review). At a minimum, Measure M6 and/or the Technical Rationale should provide more information about what an acceptable limitation might be and guidance for CMEP staff to use in evaluating the validity of limitations and the associated documentation.

The second bolded portion ("shall communicate each equipment limitation to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s)") is necessary, but may not be effective from a reliability perspective. A mere description of a limitation sent in an email or letter would not be useful for the PC/TP/RC but would meet the letter of Requirement R6. If the purpose of the communication is for PCs, TPs, and RCs to be able to assess the limitation and incorporate it into system studies, either Requirement R6 or the Technical Rationale should clarify that the communication needs to be in a format that is acceptable and useful to the PC/TP/RC (most likely in the form of an updated model that reflects the limitation). Additional burdensome administrative requirements to cover this communication process are not suggested, but at the very least the Technical Rationale should include guidance and set expectations to ensure that the communication will be useful to ensure the reliability of the grid. Additionally, ERCOT notes that FERC Order 901 recognized that "a subset of existing registered IBRs – typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements directed herein." ERCOT recommends that Requirement R6 be clarified to indicate that the equipment limitation process is only available to the limited subset of IBRs described in Order 901.

Additionally, ERCOT notes that Requirement R6, Part 6.2 does not require the TO/GO to actually improve ride-through capability even when equipment is replaced:

"Each Generator Owner and Transmission Owner with a previously communicated equipment limitation that repairs or replaces the equipment causing the limitation shall document and communicate such equipment changes to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s) within 30 days of the equipment change."

Rather than focusing on communication of changes, Part 6.2 should require the TO/GO to comply with all PRC-029 requirements and should not allow any documented limitations whenever equipment is changed or replaced; this approach would better align with FERC Order 901. PRC-029 should also include a requirement that mandates the implementation of software settings changes and upgrades (that do not require replacement of physical equipment) that improve ride-through capability. This is referenced in the implementation plan, but is absent from the actual requirements in PRC-029.

Equipment limitations may also not be currently captured in dynamic models, and the list of requirements should be updated to reflect this issue. The MOD standards may not accurately account for the provision of this information to all entities that perform studies (including stability limit and IROL determination studies that RCs perform); this would constitute a reliability gap. RCs and PC/TPs must be able to assess the impact of these exemptions to be able address the reliability impact under FERC Order 901.

Finally, ERCOT notes that FERC Order 901 requires NERC to "determine whether the new or modified Reliability Standards should provide for a limited and documented exemption for certain registered IBRs from voltage ride through performance requirements. Any such exemption should be only for voltage ride-through performance for those existing IBRs that are unable to modify their coordinated protection and control settings to meet the requirements without physical modification of the IBRs' equipment." While it is clear that the SDT has determined that the standard should allow for documented exemptions for equipment limitations, the requirement language is unclear as to how or whether this exemption process is truly "limited" as required in Order 901, especially in light of the explicit reference to IBRs "that are *unable* to modify their coordinated protection and control settings to meet the requirements without physical modification of the IBRs' equipment." As ERCOT notes below, exemptions should be limited to scenarios where a responsible entity cannot otherwise achieve the necessary ride-through performance without physical equipment changes (inability to meet ride-through requirements that can be addressed simply by making software- or parameterization-type changes should not be grounds for an exemption) OR to scenarios where, even without making the remaining physical changes, the loss of a contingency would not cause instability, Cascading Outages, or uncontrolled separation that adversely impact the BPS.

Likes 0	
Dislikes 0	

Response

Shonda McCain - Omaha Public Power District - 6

Answer	No
Document Name	

Comment

OPPD supports comments provided by GRE: Michael Brytowski, Great River Energy, 3, 4/17/2024

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	

Comment

Requirement 1 and 2

These requirements mention that the IBRs should respond to the voltage changes with reactive current injection during a system disturbance, however, the magnitude of this response is not identified. The magnitude and expectation of the response should be clarified due to the fact that it can vary by unit and unit capabilities.

Measures 1, 2, 3, 4, and 5

With regards to data recording, it is unclear what counts as recording? If the expectation is the same as contained in PRC-028-01 Draft 2, that should be specified; or otherwise identify alternate means of data recording.

What if an entity does not have a recorded event to show compliance with the standard and prove its ability to ride through a system event?

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	No
Document Name	

Comment

NextEra aligns with EEI's comments:

EEI agrees with most of the proposed language in Requirements R1, R2 and R6; however, the phrase “of an applicable IBR” should be removed. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant.

EEI also does not support Requirement R2, subpart 2.5 because it contains unneeded language, which adds confusion and implies that GOs can only trip outside of the trip zone if their equipment might become damaged. This has never been an obligation for synchronous generators, and we do not agree that this should be an obligation for IBRs. If NERC or the SDT believe that the no-trip zone needs to be expanded, they should justify such a change and present it for industry review and comment, otherwise, Requirement R2, subpart 2.5 should be deleted.

And while we support Requirement R6 and the provisions to notify PCs, TPs and RC about equipment limitations that would prevent an applicable IBR from meeting ride-through requirements as detailed in Requirements R1 and R2, the Requirement does not go far enough because there may be technical reasons why an applicable IBR is unable to meet Requirement R3 through R5, as well. To address this concern, R6 should be expanded to include Requirement R1 through R5.

Likes 0	
Dislikes 0	

Response

Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

In regard to R1:

Does M1 imply that actual recorded data must be kept as evidence of ride-thru compliance for every in-scope IBR, for every system disturbance? Thesame question applies to R2-M2, R3-M3, R4-M4, and R5-M5.

The disturbance characteristic must be specified in order to trigger captures of performance information for every disturbance at every IBR facility - the characteristic which defines each type of disturbance must be defined in order to capture the record.

For each of the Measures M1 - M5, what "other evidence" can demonstrate compliance with R1-R5 other than recorded data? How does the drafting team believe that generator owners can assure this performance expectation can be achieved prior to an actual event? There is no test verification that can be performed to confirm the expected performance. Consider providing some examples of what is acceptable as “other evidence”.

R1 mentions “operation regions specified in Attachment 1. R2, Part 2.1 mentions “continuous operation region as specified in Attachment 1” and Part 2.2 mentions “mandatory operation regions as specified in Attachment 1”. However, nowhere in attachment 1, is there mention of "continuous, mandatory, or permissive" operation regions.

In regard to R2:

For R2, Continuous Operation Region is not specified in Att. 1; it is merely a defined term in the draft standard. Southern Company suggests that the referenced region be shown on the graph of Att.1, or that the words from the defined term simply be placed in the sub-requirement directly rather than creating a defined term. The term region implies an area (volt-time). If the definition is simply specifying voltage level magnitude, simply state that. The definition labels are confusing; does permissive operation mean the IBR has permission to trip if the voltage is less than 0.1pu? It is observed that the values in the "mandatory operating region" match some of the borders of the "no trip zone" in Attachment 1, yet there is a time element that must be accounted for in determining if a trip is in compliance or not with the curve of Att. 1. For example, how can a long term (1-9 second) event where the voltage is 0.4pu be a Mandatory Operating Region? The voltage ride-thru curve does not specify this (for example).

Regarding the R2.2 and R2.3 requirement specifications, IBR facilities do not have per phase voltage regulation in their current designs, so the feasibility of successfully reacting to low system voltage (R2.2) with rapid reactive power injection while not possibly causing high voltage locally (R2.3) is questionable.

Regarding R2.1.1 & R2.1.2, it should also reference Interconnection Agreements (IA) limits since some IBR facilities have both solar and battery storage with an IA limit less than the aggregate sum.

Regarding R2.1.1 and R2.1.2, the idea that IBR Facility Power Plant Controllers operate to apparent power limits, is not in line with normal practices. Most PPC interfaces do not provide an apparent power reading or control function option. PPCs communicate separate MW and MVAR setpoints to all the of the site IBR Units and they follow or provide as capable the MWs and deliver MVARs up to the inverter reactive power limit.

Southern Company recommends changing wording to:

R2.1.1:Continue to deliver the predisturbance level of active power or available active power, whichever is less, and continue to deliver active p ower and reactive power up to its reactive power limit.

R2.1.2:If the IBR cannot deliver both active and reactive power due to a current or reactive power limit, when the applicable voltage is below 9 5% and still within the Continuous Operation Region, then preference shall be given to active or reactive power according to requirements spec ified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

R2.1.2 discusses giving preference to either active or reactive power based on requirements specified by transmission entities. There is some concern that this could be interpreted as a fluid preference that could require IBRs to actively configure active vs reactive capabilities.

Regarding R2.3, what happens if TOP has several lines down for maintenance in the area, which causes the part of the system the IBR facility is located, go from a strong system to a weak system?

R2.4 does not take into consideration other dynamic system conditions as a result of the fault and the effects on the PPC during a fault recovery. An example of this is Primary Frequency Response due to system frequency excursions during fault recovery. The active power recovery may be reduced or frozen during an underfrequency event while an IBR Resource is in recovery, thereby extending the time of the recovery.

R2 specifies performance for continuous and mandatory operation region, but not for permissive operation region. The performance during permissive operation region is in Attachment 1. Performance for all regions should be in Requirement R2.

Regarding R2.1.1, the first part, where IBR is required to continue to deliver the pre-disturbance level of active power or available active power, whichever is less is fine. However, the second part (and continue to deliver active power and reactive power up to its apparent power limit) is conflicting with the first part of this requirement. If the IBR plant's available active power was 50% of nameplate rating due availability of wind, solar irradiance, etc., then the second part of the requirement is stating that plant is required to produce reactive power to its apparent power limit given its available active power equal to 50% of nameplate rating. This is not correct.

In regard to R2.1, the clause 7.2.2.2 of the IEEE Std 2800 includes an exception when negative-sequence voltage is higher than certain threshold for a given time duration. Why the SDT not include this exception in the PRC-029?

In regard to R2.2, it appears the intent is to require that inject balanced current, during symmetrical faults, and unbalanced current during asymmetrical faults. However, the language is confusing. First, there is no plant level voltage regulation during a fault condition. Second, during unbalanced faults, what does a voltage regulation mean? One option is replace both Part 2.2.1 and Part 2.2.2 with following: The IBR shall inject current based on voltage deviation on high-side of main power transformer and as specified by the TP, PC, RC, or TOP.

In regard to R2.3,this requirement is confusing. Table 1 and 2 in Attachment 1 includes both low- and high-voltage thresholds. One meaning could be that the IBR shall not cause voltage to exceed LVRT threshold for a specified time duration. The true meaning is unclear. Is it correct that the intent is to focus on HVRT thresholds and time duration? The time duration for voltage > 1.2 per unit is not specified. Does this mean that IBR shall not cause overvoltage > 1.2 per unit whatsoever? If so, it needs to be written clearly.

In regard toR2.5, if there is no expectation for IBR to ride-through disturbance outside of no-trip zone, then there is no need for this requirement. For example, if voltage is zero for greater than specified time duration in Tables 1 and 2, say 1 second, then what is the point in staying connected and feeding into fault unless there is a risk of equipment damage? Additionally, there is no such expectation for frequency ride-through requirement R4.

R2.5 is not practical for the GO to determine where every individual piece of equipment would be damaged. There is no need to require tripping just before equipment damage if IEEE 2800 is guidance for equipment manufacturers.

In regard to Attachment 1:

1. There is no mention of continuous, mandatory, or permissive operation region in tables 1 and 2. Consider adding a column in tables 1 and 2 to show these operation regions.
2. For Table 1 and 2:
    - ≥1.20 should be >1.2
    - ≥1.1 should be >1.1
    - ≥1.05 should be >1.5
3. In IEEE Std 2800, the cumulative ride-through duration of 1800 second when voltage is > 1.05 is applicable to all nominal voltages except for 500kV nominal operating voltage. For 500kV nominal operating voltage, the equipment rated to 550kV (1.10 per unit) is available per ANSI C84.1. In IEEE Std 2800, see Note 1 under Table 12. Consider clarifying this in the PRC-029.
4. Note 7: A time window of 10-second is mentioned. However, when V>1.05, the ride-through duration is 1800 second, which is over a 3600-second time window in IEEE 2800.
5. Note 10: The purpose of current blocking in IEEE 2800 was not to protect the equipment but to rather to avoid tripping due to consequences of injecting current and hence, failure of ride-through.
6. Figures 1 & 2: why does the X-axis start at 0.1 second and not zero?

Finally, Southern Company supports EEI and NAGF comments.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	No
Document Name	
Comment	
In 2.1.1 the "apparent power limit" is what is capable during the System disturbance correct? What is the "applicable voltage" to determine 95% in 2.1.2 (and why is per unit not used)? Where are the "requirements specified" by the TP/PC/RC/TOP and how does a GO or TO determine which one to use? If in the Planning world, the requirements should be specified in the TPL Standards. It is unclear what actions a TO/GO will take and be consistently applied. Since this is an event driven compliance review in the Operations Assessment time horizon, why would a TP or PC provide preference for active or reactive power in that timeframe? In a response study by the TP/PC, perhaps guidance on preference could be provided but it is unclear and NOT required in TPL Standards to this point. Clarity between the Tables and Figures in Attachment one needs provided to avoid confusion. Just to be clear, It appears that any new units after the effective date of this Standard have to meet all the criteria. Do the existing units with limitations have six months after the effective date of Standard to submit equipment limitations. With PRC-024-3 and PRC-024-2 already having a Requirement in place that requires limitations to be provided to the TP/PC and the industry already leaning on IRO-010 and TOP-003 for notifications, why is there a need to add an additional 6 months for Requirement R6? The RC already has communication capability with GOs.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	

Comment

R1:

R1 should be revised to directly clarify, or include a footnote to clarify, the statement “that each IBR remains electrically connected and continues to exchange current” with “electrically connected, i.e., shall not trip, and continue to exchange current, i.e., shall not enter momentary cessation” that was provided in the Technical Rationale.

Attachment 1:

There is a discrepancy between the definition of the Term “Mandatory Operating Region” which states “≤ 1.2 per unit” and Table 1/Figure 1 or Table 2/Figure 2 which state “≥1.200” per unit “N/A”. Please clarify if Table 1/Figure 1 and Table 2/Figure 2 should state “>1200” or if the definition of the Term “Mandatory Operating Region” should state “<1.2 per unit”.

Please clarify Figure 1 and Figure 2 to clearly show the “Continuous Operating Region”, “Mandatory Operating Region”, and “Permissive Operating Region”, along with requirements beyond 10 seconds.

Please Clarify “9. The IBR may trip for more than four deviations of the applicable voltage….” In attachment 1.

R2.5:

This requirement is beyond the purpose of the standard, which is to establish Frequency and Voltage Ride-through Requirements for Inverter -Based Generating Resources and should be removed.

Likes 0	
Dislikes 0	

Response

Dave Krueger - SERC Reliability Corporation - 10

Answer	No
Document Name	

Comment

On behalf of the SERC Generator Working Group:

R2.4 does not take into consideration other dynamic system conditions as a result of the fault and the effects they can have on the PPC during a fault recovery. An example of this is Primary Frequency Response due to system frequency excursions during fault recovery. The active power recovery may be reduced or frozen during an over-frequency event while an IBR Resource is in recovery, thereby extending the time of the full recovery.

R2.5: It is not practical for the GO to determine where every individual piece of equipment would be damaged, nor should the GO be required to subject equipment to failure by trying to identify that point, run to it, and risk damaging it.

Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG supports IESO's comments.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
EEI agrees with most of the proposed language in Requirements R1, R2 and R6; however, the phrase "of an applicable IBR" should be removed. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant. EEI also does not support Requirement R2, subpart 2.5 because it contains unneeded language, which adds confusion and implies that GOs can only trip outside of the trip zone if their equipment might become damaged. This has never been an obligation for synchronous generators, and we do not agree that this should be an obligation for IBRs. If NERC or the SDT believe that the no-trip zone needs to be expanded, they should justify such a change and present it for industry review and comment, otherwise, Requirement R2, subpart 2.5 should be deleted. And while we support Requirement R6 and the provisions to notify PCs, TPs and RC about equipment limitations that would prevent an applicable IBR from meeting ride-through requirements as detailed in Requirements R1 and R2, the Requirement does not go far enough because there may be technical reasons why an applicable IBR is unable to meet Requirement R3 through R5, as well. To address this concern, R6 should be expanded to include Requirement R1 through R5.	
Likes 0	
Dislikes 0	
Response	

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	No
Document Name	
Comment	
Vistra agrees with Invenergy	
Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power (MP) agrees with the MRO NSRF's comments on R1, R2, and R6, and the associated graphics from Attachment 1. Additionally, MP notes that language from the Technical Rationale document specifies that R2.1, R2.3, and R2.4 are intended to apply when system conditions return to the Continuous Operation Region from the Mandatory or Permissive Operation regions. This should be specified in the standard. Finally, MP proposes the following language changes to eliminate any possible uncertainty: Section 2.1: "current or apparent power limit" to "current limit or apparent power limit" Section 2.4: "pre-disturbance or available level" to "pre-disturbance level or available level, whichever is lesser"	
Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	

Constellation does not agree and feels the HVRT times are very high. Many wind turbines/inverters won't be able to meet those times, equipment in general and these systems have not been designed to withstand that much overvoltage. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Maozhong Gong - GE - GE Wind - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
For R6, R3,R4,R5 should be included as well for the documented limitation communication (see R6 comments below)	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Imane Mrini - Austin Energy - 6, Group Name Austin Energy	
Answer	No
Document Name	
Comment	

AE supports comments provided by Texas RE and the NAGF

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

EEI agrees with most of the proposed language in Requirements R1, R2 and R6; however, the phrase “of an applicable IBR” should be removed. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant.

EEI also does not support Requirement R2, subpart 2.5 because it contains unneeded language, which adds confusion and implies that GOs can only trip outside of the trip zone if their equipment might become damaged. This has never been an obligation for synchronous generators, and we do not agree that this should be an obligation for IBRs. If NERC or the SDT believe that the no-trip zone needs to be expanded, they should justify such a change and present it for industry review and comment, otherwise, Requirement R2, subpart 2.5 should be deleted.

And while we support Requirement R6 and the provisions to notify PCs, TPs and RC about equipment limitations that would prevent an applicable IBR from meeting ride-through requirements as detailed in Requirements R1 and R2, the Requirement does not go far enough because there may be technical reasons why an applicable IBR is unable to meet Requirement R3 through R5, as well. To address this concern, R6 should be expanded to include Requirement R1 through R5.

Likes 0	
Dislikes 0	

Response

Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3

Answer	No
Document Name	

Comment

R1/R2: Recommend that Attachment 1 have a chart to include the Continuous Operation Region, Mandatory Operation Region, and Permissive Operation Region or have those regions specified on existing Voltage Ride -through Requirements Figure 1 and Figure 2.

Requests the SDT review and align the data in **Attachment 1** so the data in Tables 1 and 2 aligns with what is shown in Figures 1 and 2. Currently, the graphs in Figures 1 and 2 do not match what is indicated in the Tables.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy recommends the implementation of EEI and NAGF comments.

Duke Energy does not agree that the language is clear. The language seems close to but not completely in alignment with IEEE 2800-2022. It is not clear that the -029 requirements align with the IEEE 2800 requirements, especially given that most would want to comply with both. Many times the Continuous Operation Region is associated with the voltage regulation function and the Mandatory Operation Region is associated with LVRT. This separation is not maintained in various statements within 2.1 and 2.2. It is not clear how the plant or inverters can be configured to operate as specified in R2. Overall the language seems overly prescriptive and the DT may consider less specificity and possibly even a reference to IEEE 2800 rather than trying to restate it. Voltage regulation functions are typically based on POI voltage while LVRT functions are based on inverter terminal voltage. It is not clear that the requirements recognize this difference.

Also, there are multiple references in R1 and R2 to Attachment 1 containing or representing the various Regions, but they are not graphically represented. The DT may consider revising the Att. 1 Figures (and moving the vertical axis crossing to 0.1 sec).

tt seems the industry has often misinterpreted the area outside of the No-trip Zone as an area where the plant must trip. The DT may consider specifically addressing and emphasizing in the text and on the Figure that the plant is not required to trip in this area. For example, it may be labeled May Trip Zone. To that end, it would also be helpful for the GO to submit equipment ride through limits. That is the actual equipment limits, not the various voltage protection settings. With that information, plants would have the bases to provide the maximum ride-through beyond the No-Trip Zone and still not exceed plant main and BOP equipment limits.

Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	

WEC Energy Group does not agree that the language in R1, R2, and R6 is clear for the following reasons:

R1.:

WEC disagrees with text "… shall ensure that each IBR remains connected…". How else can an entity "ensure" to remain connected other than to set voltage protection outside the no-trip zone? The requirement must state what must be done. Based on Attachment 1, this is clearly voltage protection settings function so R1 should try and match PRC-024 R1. Otherwise, this requirement is open-ended as IBR could potentially be disconnected due to other reasons and the entity will be deemed non-compliant.

The "main power transformer" should be defined in a footnote, similar to what's proposed in PRC-028. It's unclear if main power transformer represents individual IBR step-up transformer or the site step-up transformer.

The phrase "exchange current" should be listed and defined in Terms section. Confusion exists in understanding if "exchange current" applies to BESS while charging, real/reactive current components, or something else. An exception should be added to exclude BESS from the PRC-029 requirements while charging.

WEC also disagrees with M1. The only means for an entity to "ensure IBR remains connected" is to set voltage protection and voltage ride-through protection according to Attachment 1. Making sure that the settings are applied should be the measure. The "recorded data" is an inconclusive statement. If the entity applied settings outside the no-trip zone and it still tripped, which could be for various other reasons, does that mean then entity is non-compliant? What needs to be recorded and where? Does this measure now mandate additional recording capabilities in addition to PRC-030? (Same comment applies to M2, M3, and M4).

R2.:

WEC disagrees with text "…. shall ensure that each IBR remains connected…". The requirement must state what TO and GO must do. Otherwise, this requirement is open-ended without a measurable statement.

2.1: Term "Continuous Operating Region" as defined conflicts with equipment design limitations. Power transformers may not be designed for continuous operations from 0.9 and 1.1 pu. Please refer to IEEE C57.12.00, sections 4.1.6.1, 4.1.6.2 and 5.5, and ANSI C84.1. Without some specific maximum time applied, the continuous operating region will conflict with equipment limitations. Due to this wide range, entities will simply take exception to R2 and R2 will not have any positive benefit for BES reliability. There is a reason PRC-024-3 has a 4 second limit. This limitation should clearly be introduced in PRC-029. Finally, the proposed "Continuous Operating Region" range conflicts with acceptable continuous operating ranges by Transmission Operators. Many Transmission Operators classify continuous operating range from 0.95 and 1.05 pu, and consider voltage ranges from 0.9 to 0.95 pu and 1.05 to 1.1 pu as abnormal voltage ranges.

2.1.2: There is nothing that governs a TP, PC, RC or TO to specify active/reactive power prioritization.

2.3: This requirement is inconclusive. The requirement must state what TO and GO must do. Otherwise, this requirement is open-ended without a measurable statement. Something regarding "IBR gain" was briefly mentioned during the PRC-029 webinar. A wide spectrum of gains and tuning parameters exist within the IBR controls. The requirement must state what parameters are to be addressed and how to set them. Gains and tuning parameters are covered in MOD-026 and MOD-027 standards and shall not be introduced here. Another potential issue could be with AVR function within the power plant controller. AVR/PPC failure could potentially cause higher voltage outputs. AVR failure, or any equipment failure, should not be the criteria to violate the standard. WEC recommends this requirement be removed.

2.4: WEC owns and operates multiple IBR sites and it is in our experience that the limitation to the 1 second requirement will come from the power plant controller. The ramp rate capabilities of the power plant controllers are far slower than inverter ramp rates and are typically in minutes range. WEC also had an instance where the power plant controller ramp rate increase was denied by the Transmission Operator/Planner.

2.5: This requirement contradicts the meaning of established No-Trip zone. If the No-Trip zone is inadequate, then SDT should evaluate and adjust it accordingly. In addition, having protection settings applied right at the equipment damage curve is not a standard protection practice, especially if events such as voltage excursions have a cumulative effect on insulation degradation that could lead to premature failures. WEC recommends this requirement be removed.

R6.: This requirement should include and cover equipment limitations associated with R3, R4, and R5.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

The NAGF provides the following comments:

a. Requirement R1 - the NAGF request clarification on the term "exchange" being used in the proposed language for Requirement R1.

b. Requirement R2 – the Terms section identified the terms: Continuous Operating Region, Mandatory Operating Region, and Permissive Operating Region but these terms are not specifically referenced in the tables for Attachment 1. The NAGF believes that the regions should be included in Attachment 1 for clarity.

c. The PRC-029-1 draft remains silent on the network condition, so it is unclear how to model the transmission system to test compliance with these requirements. One option is to assume that the transmission grid at the point of interconnection may be modeled as an ideal voltage source. Another option is to model the transmission grid as a voltage with a Thevenin impedance based on a short circuit ratio (minimum and maximum), which would consider the network condition at the point of interconnection. The NAGF requests clarity on this topic regarding testing compliance.

d. The requirement stated in R2.4 for IBRs to restore active power to the pre-disturbance or available level within 1.0 second when voltage at high-side of the main power transformer returns to Continuous Operation Region. Based on the TO studies or requirements, it is recommended that flexibility be allowed in the recovery time requirement. For example, if studies indicate that a slower ramp-rate and/or pause in the power ramp-up is beneficial then that should be allowed. The NAGF also recommends an active power recovery threshold of 90% of pre-disturbance level to account for measurement and IBR unit control uncertainties and tolerances.

e. The requirement stated in R2.1.1 must allow IBRs apparent power to be limited if the voltage is outside the normal operating range and the IBR units have reached their maximum current limit.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

AZPS supports the following comments that were submitted by EEI on behalf of its members:

EEI agrees with most of the proposed language in Requirements R1, R2 and R6; however, the phrase “of an applicable IBR” should be removed. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant.

EEI also does not support Requirement R2, subpart 2.5 because it contains unneeded language, which adds confusion and implies that GOs can only trip outside of the trip zone if their equipment might become damaged. This has never been an obligation for synchronous generators, and we do not agree that this should be an obligation for IBRs. If NERC or the SDT believe that the no-trip zone needs to be expanded, they should justify such a change and present it for industry review and comment, otherwise, Requirement R2, subpart 2.5 should be deleted.

And while we support Requirement R6 and the provisions to notify PCs, TPs and RC about equipment limitations that would prevent an applicable IBR from meeting ride-through requirements as detailed in Requirements R1 and R2, the Requirement does not go far enough because there may be technical reasons why an applicable IBR is unable to meet Requirement R3 through R5, as well. To address this concern, R6 should be expanded to include Requirement R1 through R5.

Likes 0	
Dislikes 0	

Response

Joy Brake - Nova Scotia Power Inc. - NA - Not Applicable - NPCC

Answer	No
Document Name	

Comment

Concerns are covered other commenters.

Likes 0	

Dislikes 0	
Response	
Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	No
Document Name	
Comment	
PNM agrees with the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
R2.1/2.2 This states that the TO is who decides whether Active or Reactive Power is prioritized when a limit is reached. IBR sites will curtail real power to meet the reactive power request from the controllers. R2.4 This section would depend on the ramp rate of the units, 1.0 seconds seems extreme M2 Will the PC's be communicating in writing to the Generator Owner every time there is a disturbance with the request for this data. How long will the data need to be held? R4 5 hz/second is not a reasonable rate M4	

Will the PC's be communicating in writing to the Generator Owner every time there is a disturbance with the request for this data. The retention period for data is not defined.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and North American Generator Forum (NAGF) on question 2

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy supports EEI comments. In addition, Dominion Enetgy has the following comments:

R2, Section 2.1 refers to the Continuous Opera**tion** Region as specified in Attachment 1; however the definition of Continuous Opera**ting** Region at the beginning of the standard is only applicable to voltages, measured at the high-side of the MPT that are between 0.9 PU and 1.1 PU. Does this mean that the definition of Continuous Operation Region is different from Continuous Operating Region? Or is the intent the same as the definition at the front of the standard and the “tion” should be changed to “ting”? Please clarify. This disconnect also exists in R2 and in R2.2.

R2, Section 2.1.2 and R2.4 both allude to a requirement for either the Transmission Planner, Planning Coordinator, Reliability Coordinator or Transmission Operator to provide a preference of active or reactive power if an IBR cannot deliver both due to a current or apparent power limit. The standard is not applicable to any of these listed entities and thus puts an administrative burden on the Generator Owner to contact each to determine a preference. Four entities determining the preference is three too many. A new requirement should be written directing one of the four entities to be the lead point of contact for the GO. Additionally, the standard should specify that the lead entity charged with determining the preference of active of reactive power should communicate the preference a minimum of 6 months prior to the effective date for the GO. The GO cannot put controls in place and ensure compliance until the TP, PC, RC or TOP has documented the compliance requirement.

R6, Section 6.2 is confusing since the Technical Rationale and FERC Order 901 Directives, Paragraph 193 states that “when the existing equipment is replaced, the exemption would no longer apply, and the new equipment must comply with the appropriate IBR performance requirements”. Further, FAC-002-5 considers replacement of inverters / converters or Power Plant Controllers to be “qualified changes” and would require a study before implementation. This section seems to be an unnecessary administrative step, since the FAC-002 process would require submittal of “as-built settings” for the qualified change study.

Likes 0	
Dislikes 0	

Response

George E Brown - Pattern Operators LP - 5

Answer	No
Document Name	

Comment

Pattern Energy supports GRE’s comments for this question.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

Constellation does not agree and feels the HVRT times are very high. Many wind turbines/inverters won't be able to meet those times, equipment in general and these systems have not been designed to withstand that much overvoltage.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	

1 The language “continues to exchange current” in R1 is not clear, please explain.

2 OEMs have not been forthcoming with operating limit data/equipment trip capabilities. Due to the lack of information from OEMs, we are concerned that the following language in R2.5 will be difficult to comply with: “Each IBR shall only trip *to prevent equipment damage*, when the voltage at the high-side of the main power transformer is outside of the no-trip zone as specified in Attachment 1”.

3 The SDT should consider equipment where the manufacturer is not able to provide the limits where equipment damage can occur. For legacy equipment, this information may not be available or may be available at a very high cost to the GO. These scenarios should be included as limitations.

4· Charts in Attachment 1 should be updated to graphically show the performance regions

Likes 0	
Dislikes 0	
Response	

Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	

No, Invenergy disagrees that the language within PRC-029-1 requirements R1, R2, and R6 is clear. Specifically, we offer the below comments regarding these requirements:

R2.1.1.: As currently drafted, R2.1.1. seems to ignore the changes to apparent power limits that could occur during a System disturbance. We recommended the following language:

“R2.1.1. Continue to deliver the pre-disturbance level of active power or available active power, whichever is less, and continue to deliver active power and reactive power up to *the total aggregated current rating of the IBR Units in the plant*.”

R2.1.2.: Invenergy is concerned that the language in R2.1.2. regarding the active power or reactive power preferences of TPs, PCs, RCs, or TOPs may lead to increased confusion and unintended consequences. In its place, we recommend adopting something similar to the p/q/v capability curve demonstrated in Figure 8 of IEEE 2800-2022.

R2.3.: It is unclear to us what R2.3. is requiring. Please clarify or remove.

R2.4.: The ramp rate should be based on System needs; in weaker grid conditions such rapid ramping of active power could lead to power-oscillations or small-signal instability.

R2.5.: This requirement is not auditable and is beyond the scope of the standard, which is to establish certain minimum ride-through requirements. As written, R2.5. suggests GOs should push their equipment as near to its breaking point as possible, even after the minimum ride-through requirements have been met. Thus, we ask R2.5. and similar statements throughout the draft standard be removed.

R6.: Given the technical limitations of many legacy IBRs, R6 must be thoroughly amended to allow exemptions for limitations related to frequency, rate-of-change-of-frequency, and phase angle change ride-through requirements. Consider that there are a range of possible concerns with legacy equipment and equipment already in commercial operation. At one end of the spectrum there exists legacy equipment where the manufacturer is no longer in business, or no longer produces the given IBR unit technology. In these cases, it is often infeasible to either truly document all aspects of the equipment limitations or to attempt to make any software or hardware modifications. At the other end of the spectrum there exists equipment that has been installed in recent years where software modifications may be enough to bring the units into compliance with the proposed requirements, after proper due-diligence and analyses have been performed. In between these two ends of the spectrum there is a range of possibilities.

Where available, software-only modifications are the most likely to yield meaningful reliability improvements where they are most needed while being technically and financially feasible for legacy IBRs to deploy. Indeed, the vast majority of performance issues identified with solar PV resources involved in the 2021 and 2022 Odessa disturbances (and other solar PV resources with the same inverter make/model that were not involved in the Odessa events) are being addressed in ERCOT with software-based modifications (see https://www.ercot.com/files/docs/2024/03/06/Odessa%20Update_03082024.pptx).

Thus, R6 needs a thorough rewrite to give due consideration, and acknowledgement, to these various nuances. Invenergy proposes the below modifications:

R6. Each Generator Owner and Transmission Owner with an applicable IBR that is in commercial operation prior to the effective date of this standard that is unable to meet the ride-through performance requirements detailed in Requirements R1 through R5 shall document the limitation, communicate each equipment limitation to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s), and provide a plan for making reasonable software and settings modifications that reduce or remove the limitation, if available and feasible.

6.1. Each Generator Owner and Transmission Owner shall include in its documentation, in each case as is available or can be reasonably obtained:

6.1.1. Identifying information of the IBR (name, facility #, other)

6.1.2. Current ride-through capability

6.1.3. Known ride-through limitations and documentation of such limitations

6.1.4. Reasonable software and settings modifications

6.1.5. Expected post-modification ride-through capability and documentation of any expected remaining limitations following implementation of such modifications

6.1.6. A schedule for implementing the modifications

6.2. Each Generator Owner and Transmission Owner with a previously communicated equipment limitation that makes a modification that reduces or removes such limitation shall document and communicate such modification to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s) within 30 days of the modification.

To supplement the language regarding reasonable software and settings modifications, the following language could be added to the Technical Rationale: Reasonable software and settings modifications are any available technically feasible modifications involving only software, firmware, settings, or parameterization changes that do not require physical modification of the IBR equipment and are reasonably priced.

Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	

Ameren agrees with EEI's comments.

Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	

No, Invenergy disagrees that the language within PRC-029-1 requirements R1, R2, and R6 is clear. Specifically, we offer the below comments regarding these requirements:

R2.1.1.: As currently drafted, R2.1.1. seems to ignore the changes to apparent power limits that could occur during a System disturbance. We recommended the following language:

"R2.1.1. Continue to deliver the pre-disturbance level of active power or available active power, whichever is less, and continue to deliver active power and reactive power up to *the total aggregated current rating of the IBR Units in the plant*."

R2.1.2.: Invenergy is concerned that the language in R2.1.2. regarding the active power or reactive power preferences of TPs, PCs, RCs, or TOPs may lead to increased confusion and unintended consequences. In its place, we recommend adopting something similar to the p/q/v capability curve demonstrated in Figure 8 of IEEE 2800-2022.

R2.3.: It is unclear to us what R2.3. is requiring. Please clarify or remove.

R2.4.: The ramp rate should be based on System needs; in weaker grid conditions such rapid ramping of active power could lead to power-oscillations or small-signal instability.

R2.5.: This requirement is not auditable and is beyond the scope of the standard, which is to establish certain minimum ride-through requirements. As written, R2.5. suggests GOs should push their equipment as near to its breaking point as possible, even after the minimum ride-through requirements have been met. Thus, we ask R2.5. and similar statements throughout the draft standard be removed.

R6.: Given the technical limitations of many legacy IBRs, R6 must be thoroughly amended to allow exemptions for limitations related to frequency, rate-of-change-of-frequency, and phase angle change ride-through requirements. Consider that there are a range of possible concerns with legacy equipment and equipment already in commercial operation. At one end of the spectrum there exists legacy equipment where the manufacturer is no longer in business, or no longer produces the given IBR unit technology. In these cases, it is often infeasible to either truly document all aspects of the equipment limitations or to attempt to make any software or hardware modifications. At the other end of the spectrum there exists equipment that has been installed in recent years where software modifications may be enough to bring the units into compliance with the proposed requirements, after proper due-diligence and analyses have been performed. In between these two ends of the spectrum there is a range of possibilities.

Where available, software-only modifications are the most likely to yield meaningful reliability improvements where they are most needed while being technically and financially feasible for legacy IBRs to deploy. Indeed, the vast majority of performance issues identified with solar PV resources involved in the 2021 and 2022 Odessa disturbances (and other solar PV resources with the same inverter make/model that were not involved in the Odessa events) are being addressed in ERCOT with software-based modifications (see https://www.ercot.com/files/docs/2024/03/06/Odessa%20Update_03082024.pptx).

Thus, R6 needs a thorough rewrite to give due consideration, and acknowledgement, to these various nuances. Invenergy proposes the below modifications:

R6. Each Generator Owner and Transmission Owner with an applicable IBR that is in commercial operation prior to the effective date of this standard that is unable to meet the ride-through performance requirements detailed in Requirements R1 through R5 shall document the limitation, communicate each equipment limitation to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s), and provide a plan for making reasonable software and settings modifications that reduce or remove the limitation, if available and feasible.

6.1. Each Generator Owner and Transmission Owner shall include in its documentation, in each case as is available or can be reasonably obtained:

6.1.1. Identifying information of the IBR (name, facility #, other)

6.1.2. Current ride-through capability

6.1.3. Known ride-through limitations and documentation of such limitations

6.1.4. Reasonable software and settings modifications

6.1.5. Expected post-modification ride-through capability and documentation of any expected remaining limitations following implementation of such modifications

6.1.6. A schedule for implementing the modifications

6.2. Each Generator Owner and Transmission Owner with a previously communicated equipment limitation that makes a modification that reduces or removes such limitation shall document and communicate such modification to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s) within 30 days of the modification.

To supplement the language regarding reasonable software and settings modifications, the following language could be added to the Technical Rationale: Reasonable software and settings modifications are any available technically feasible modifications involving only software, firmware, settings, or parameterization changes that do not require physical modification of the IBR equipment and are reasonably priced.

Likes 0	
Dislikes 0	

Response

Brittany Millard - Lincoln Electric System - 5

Answer	No
Document Name	

Comment

A review of the data in Attachment 1 and Tables 1 and 2 should be performed so that they align. Currently, the graphs in Figures 1 and 2 do not match what is indicated in the Tables.

We would recommend a part be added to the standard to directly address the Permissive Operating Region, similar to what is done in Part 2.1 (for Continuous Operation Region) and Part 2.2 (for Mandatory Operation Region) as, if left unaddressed, is unclear. For example, there should be some linkage between the body of the standard and Attachment 1, item 10. The following language is provided for consideration (*new* Part 2.3):

2.3 While voltage at the high-side of the main power transformer is within the Permissive Operation Region as specified in Attachment 1, an IBR may operate in current block mode only if necessary to protect the equipment. Otherwise, each IBR shall follow the requirements for the Mandatory Operation Region in Requirement R2.2.

Likes 0	
Dislikes 0	

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

Comment

Plese review and align the data in Attachement 1 so that data in Tables 1 & 2 align with Figures 1 & 2.

Also, it is recommended a part be added to the standard to directly address the Permissive Operating Region, similar to what is done in Part 2.1 (for Continuous Operation Region) and Part 2.2 (for Mandatory Operation Region) as, if left unaddressed, is unclear. For example, there should be some linkage between the body of the standard and Attachment 1, item 10. See the following proposed language for consideration (*new* Part 2.3):

2.3 While voltage at the high-side of the main power transformer is within the Permissive Operation Region as specified in Attachment 1, an IBR may operate in current block mode only if necessary to protect the equipment. Otherwise, each IBR shall follow the requirements for the Mandatory Operation Region in Requirement R2.2.

OPTION A.

Requirement R6 provides an overly broad exemption as written as the standard is silent as to what criteria must be met. Only notification to other reliability entities is required with no requirement to develop and implement a Corrective Action Plan. The SDT should consider:

- Develop more specific criteria as to what qualifies as an equipment limitation[1], OR
- Require exemptions be submitted to NERC and/or the Regional Entities for approval in order to qualify for the exemption.

OPTION B.

Leave R6 as written, apply R6 to R1 through R5.

it is recommended that there be no requirement to document limitations on legacy equipment and that this standard focuses on equipment brought into service after the implementation date.

R2: We agree with the present flexibility that some of the IBR VRT performance could be modified to meet the individual system needs by the applicable Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator. However, some clarity may be required on how this process is initiated and what type is evidence is required to demonstrate request is received and implemented. This may be an additional requirement assigned to the Transmission Planner. Each Transmission Planner, Planning Coordinator, and Transmission Operator that jointly specifies the following voltage ride-through performance requirements within their area(s) different than those specified under R2, shall make those requirements available to each associated applicable IBR Generator Owner and Transmission Owner

[1] *See Implementation Plan (page 4), i.e. "only those IBR that are unable to meet voltage ride-through requirements due to their inability to modify their coordinated protection and control settings may be considered for potential exemption." See Technical Rationale (page 9); i.e. specify which voltage band(s) and associated duration(s) cannot be satisfied or specific as to the number of cumulative voltage deviations within*

a ten-second time period that the equipment can ride-through if less than four… identify the specific equipment and explain the characteristic(s) of that equipment that prevent ride-through.

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

We believe that language needs to be added to M1, similar to that provided in the other Measures, to specify the initiating event that triggers the requirement for R1 evidence of compliance.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	No
Document Name	

Comment

Black Hills Corporation supports EEI's and NAGF's comments. Additionally, Black Hills Corporation has concerns regarding event-based "Measures" for Requirement R2, R3, R4 and R5 as GO will likely not have immediate knowledge of "System disturbance" or other transmission system events (transient overvoltage due to switching, frequency excursion, instantaneous positive sequence voltage phase angle changes) when they occur and data collection systems have a limited amount of storage capacity (i.e. data overwrite happens over time, in our case, data is retained for a rolling 12 months). If available data remains the "Measure" for demonstrating compliance, then consideration needs to be given to when and how GO are notified of an event, so data can be reviewed and archived for future demonstration of compliance.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	
Comment	

FirstEnergy finds 2.4 requesting the return to of the Active Power is restrictive and needs to be inclusive of Reactive Power due to voltage response.

Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	No
Document Name	
Comment	

AECI supports comments provided by the NAGF

Likes 0	
Dislikes 0	
Response	

Brian Lindsey - Entergy - 1

Answer	No
Document Name	
Comment	

- 2.1.2 refers to requirements specified by the TP, TOP, PC, RC. It is unclear what the expectation is if those requirements have not been defined.
- Is 2.2.2 is stating that the IBR shall maintain reactive power per default setpoints unless a new reactive setpoint has been requested or it's been requested to maintain a certain active power? Why wouldn't this be worded similarly to the sub-bullets in 2.1?
- 2.3: if the IBR is already responding to Mandatory or Permissive Operation regions (exceedances of Attachment 1 Table 1 or Table 2), how could it then cause an exceedance?

- R2.4 There is concern that the controls will be either unable to respond within the 1 second timeframe, or that the historical records to prove the response would not have the resolution to be meaningful.
- R 2.5: How would someone prove that an IBR tripped only to prevent equipment damage? This sub-bullet cannot be enforced.

Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	No
Document Name	Proposed change to table Q2.PNG
Comment	

The IESO recommends the following modifications to the text improve clarity or to better convey intent.

With regards to R1:

"…as specified in Attachment 1 unless **not doing so is** needed to clear a fault or a documented **and communicated** equipment limitation exists in accordance with **Requirement R6."**

With regards to M1:

"…demonstrating adherence to ride-through requirements, as specified in Requirement R1**, or shall have evidence of a documented and communicated equipment limitation, as specified in Requirement R6**."

With regards to R2:

"…each IBR's voltage performance adheres to the following, unless a documented **and communicated** equipment limitation exists…"

With regards to 2.1: (and Tables 1 & 2, Figures 1 & 2):

There appears to be inconsistency between the definition of 'Continuous Operation Region', the Minimum Ride-Through Time values stated in Tables 1 & 2, and the plots in Figures 1 & 2.

It seems the intent is to have 'continuous' operation between 95% and 105% voltage, and a minimum ride-through time of at least 1800 seconds (half an hour) when voltage is above 105% and not exceeding 110%. If it is really required that equipment must be able to operate ***continuously*** at voltages up to 110%, then the tables and plots should be labelled with a descriptor that implies indefinite operation is required (i.e., continuous) rather than a minimum time (1800 seconds). For example, a version of Table 2 that achieves what seems to be intent could look like the following:

See file attached - Proposed change to table Q2

With regards to 2.5:

The IESO believes the principle of tripping only when necessary (i.e., to clear faults and to prevent equipment damage during disturbances) is important enough that it warrants a dedicated requirement. With regards to tripping during over-voltages, this principle of only tripping for equipment protection purposes may apply equally to system disturbances discussed in R2 and to switching transients as discussed in R3 (tripping for equipment protection is not presently addressed in R3, though is acknowledged in the Technical Rationale document).

With regards to R6:

The IESO suggests there should be explicit requirements to both 'document equipment limitations' and to 'communicate' those documented limitations to the appropriate parties. The following modifications are proposed:

"Each Generator Owner and Transmission Owner with a **known** equipment limitation that would prevent an applicable IBR that is in-service by the effective date of this standard from meeting voltage ride-through requirements as detailed in Requirements R1 and R2 shall **document** each equipment limitation **and communicate it** to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s).

With regards to M6:

Each Generator Owner and Transmission Owner shall have evidence of **known** equipment

limitations, as specified in Requirement R6, **having been** documented **and communicated** to each associated Planning Coordinator, Transmission Planner, and Reliability Coordinator prior to the effective date of PRC-029-1.

Each Generator Owner and Transmission Owner with changes to equipment shall have evidence of communication to each associated Planning Coordinator, Transmission Planner, and Reliability Coordinator.

Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power does not agree that the language in the applicability section of PRC-029-1 is clear. The applicable facilities language in Section 4 is vague and difficult for entities to understand what is in scope of the Standard. Specifically, the term "BPS IBR" is broad and would encompass all transmission connected IBRs, regardless of size or interconnection voltage. Additionally, the language and formatting of the applicability sections in PRC-028, PRC-029 and PRC-030 are not consistent. These three Standards apply to the same facilities, and therefore, should use the same language. Tacoma Power recommends that Section 4 of PRC-029 and PRC-030 should be revised to align with the language proposed in Section 4 of PRC-028, as follows:

4.1. Functional Entities:

4.1.1. Transmission Owner that owns equipment as identified in section 4.2

4.1.2. Generator Owner that owns equipment as identified in section 4.2

4.2. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	
Leah Gully - Madison Fields Solar Project, LLC - 5 - RF	
Answer	No
Document Name	
Comment	
See "additional comments" for details	
Likes 0	
Dislikes 0	
Response	
Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	2020-02_EPRI Comments on Draft NERC PRC-029 (IBR ride-through) Reliability Standard.pdf
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Goggin - Grid Strategies LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Campbell - David Campbell On Behalf of: Natalie Johnson, Enel Green Power, 5; - David Campbell	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carey Salisbury - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting	
Answer	Yes
Document Name	
Comment	

Yes. The SDT should consider citing IEEE 2800-2022 directly in the standard and consider using the IEEE 2800-2022 ride-through requirements as a means to comply with Requirements R1-R5 instead of using Attachment 1 of the standard.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Remove from R1 "*and operation regions*" since this is already required in R2.

Move R2.5 to a sub-requirement of R1, since R1 is the no-trip requirement not R2.

R2.5 should read be rearranged to be more clear, "When the voltage at the high-side of the main power transformer is outside of the no-trip zone as specified in Attachment 1, each IBR shall only trip to prevent equipment damage."

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	Yes
Document Name	

Comment

SRP believes the language in R1 and R2 provides clear expectations of how IBR controls should behave during short circuit events.

Likes 0	
Dislikes 0	

Response

Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
While the language is clear, the SDT explains in the draft PRC-029-1 Technical Rationale that "An IBR becomes noncompliant with PRC-029 only when an event in the field occurs that shows that one or more requirements were not satisfied." See Question 4 comment for RF's concerns with this approach.	
Likes 0	
Dislikes 0	
Response	
Stefanie Burke - Portland General Electric Co. - 6	
Answer	Yes
Document Name	
Comment	
PGE supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Since the evidence needed is the actual recorded data, we only need it when there's an actual event that happened in the system. What if after the event, we found out that we are not compliant? What can we do to ensure compliance? Please add more clarification about the evidence requirements.	
Likes 0	
Dislikes 0	

Response	
Wesley Yeomans - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katrina Lyons - Georgia System Operations Corporation - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	

Response

Wendy Kalidass - U.S. Bureau of Reclamation - 5

Answer	
Document Name	

Comment

Not Applicable to Reclamation.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

BC Hydro appreciates the drafting team’s efforts and the opportunity to comment, and offers the following:

1. Requirement R2 Part 2.1.2 appears to set an additional Requirement for TP, PC, RC, or TOP to specify requirements for scenarios where an IBR cannot deliver both active and reactive power when the voltage is within the Continuous Operating Region and below 95%. BC Hydro recommends that if these are intended as mandatory or deemed as a necessary input for the IBR Owner/Operator, then these should be codified as standalone Requirement(s) against the appropriate functional entities (TP, PC, RC, or TOP suggested by the current draft).

2. The VSL Table for Requirement R1 does not reflect the allowance of a documented limitation. As drafted, it implies that a Severe VSL will be assessed in spite of a preexisting and documented equipment limitation. BC Hydro recommends that the wording be revised to clarify the compliance expectations when evaluating IBR performance.

Likes 0	
Dislikes 0	

Response

3. Do you agree with the drafting team's proposals for including IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in PRC-029-1 Requirements R3, R4, and R5?

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

Designing an IBR plant for transient over-voltage ride-through compliance is complicated by separation of the IBR Units from MPT high side by the non-aggregated collector system including the MPT itself, frequency dependence of the collector system, GSU (i.e., pad mount transformers) and MPT transformer saturation, and surge arrestors on the collector system. DFRs triggered on TOV are essential for monitoring compliance.

Assessing IBR plant phase jump ride-through is dependent on being able to trigger DFR records on non-fault line switching events. Also, as the standard is now written, phase angle jump of any magnitude during a fault must be ridden through and it does not seem possible to determine if a ride-through failure is caused by a fault-caused phase jump exceeding 25 degrees (in which case the IBR could be compliant), or if instead there is a true non-conformity with R1. AEP is not aware if anything can be done about this, but it may be a minor point in most practical situations.

Regarding R4, the technical rationale supporting the standard seems to neglect the possibility of torsional interaction between the wind facilities where sub-synchronous control interaction could exist that can result in possible damage to the wind turbine generator shaft. Therefore, a blanket statement that an inverter-based resource is not affected by off-nominal frequencies may be an assumption that should warrant further considerations when establishing inverter-based resource, frequency ride through requirements. We believe this is supported by page 6 of the technical rationale which states *"In the case of the non-hydraulic turbine synchronous resources, the turbine is usually considered to be more restrictive than generator in limiting IBR frequency ride-through because of possible mechanical resonances in the many stages of turbine blades. Off-nominal frequencies may bring blade vibrational frequencies closer to a mechanical resonate frequency and cause damage due to the vibration stresses. However, inverter- interfaced-IBR does not share this vibrational failure mode."* Furthermore, how should phase jump be considered in R5 where synch check relay settings are greater than 25 degrees?

Likes 0	
Dislikes 0	
Response	

Leah Gully - Madison Fields Solar Project, LLC - 5 - RF	
Answer	No
Document Name	

Comment	
See "additional comments" for details	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State is concerned with the big jump from 61.8 to 64 under Attachment 3, Table 4. We would like to suggest the ride-through requirement be at 62 or 63.	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	No
Document Name	
Comment	

- R3:
  - Technical Rationale "High Voltage Ride Through and Low Voltage Ride Through" modes were not clearly defined. "Mode" implies a specific, programmed, set of actions within controls which may not be real for solar sites.
  - A GO may not know if a switching event occurs. In that case, how would a GO be expected to determine if the event in question is a switching event or not? While R6 addresses exemptions for R1 and R2 in the case that equipment or the ability to record doesn't exist in an existing site, the same may be of concern for the sub-second requirements listed in R3, 4 and 5. The same exclusions should be for the entire standard, if applicable.
- R4:
  - If the Rate of Change of Frequency is 5 Hz/second, there's concern that the level of calculation needed on parameters that may not have more than a 1/second resolution would net little reaction.
- R5:

- While R6 addresses exemptions for R1 and R2 in the case that equipment or the ability to record doesn't exist in an existing site, the same may be of concern for the sub-second requirements listed in R3, 4 and 5. The same exclusions should be for the entire standard, if applicable.

Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
AECI supports comments provided by the NAGF	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports NAGF's and EEI's comments. Additionally, see "Measures" concern noted above in Q2.	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	

No, Invenergy disagrees with the proposals for including IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in Requirements R3, R4, and R5. We offer the below comments regarding these Requirements:

R3: Can the drafting team provide data that demonstrates observed overvoltages during recent System events were of the TOV magnitudes and durations defined in Attachment 2 Table 3? TOVs of such scale are primarily due to the following three scenarios: 1) a lightning strike on the nearby transmission system, 2) transmission line switching transients, and 3) resonant phenomena like voltage magnification due to shunt capacitor switching on the transmission system. Measures are already in place to mitigate such events, including but not limited to proper insulation coordination and substation design, metal oxide varistors, and proper capacitor bank switching of transmission level shunt capacitors (e.g. synchronous switching or use of pre-insertion resistors to mitigate voltage magnification to the extent possible).

To support our statement above, consider an often-quoted document to support these TOV requirements in the NERC Odessa Disturbance Texas Events: May 9, 2021 and June 26, 2021 Joint NERC and Texas RE Staff Report, Dated September 2021. A detailed read of the section that is entitled Inverter Transient AC Overvoltage Tripping Persists identifies poor coordination of controls and protection as the primary driver of these events, rather than TOV conditions at the point of measurement due to switching transients or any type of resonance. What the report explains is that in some cases the IBR units force maximum reactive power output during a fault to push the network voltages up, then once the fault clears they do not pull back on the reactive power injection quickly enough, which leads to an RMS over-voltage (not switching event TOV) at the terminals of the IBR unit, and thus the IBR units tripped. This is solved by 1) proper controls and protection coordination, 2) proper IBR plant design, and 3) proper evaluation of the LVRT and HVRT ride-through capabilities of the IBR plant during the design phase of the plant.

R3 should be removed, and the focus placed on low voltage ride-through and high voltage ride-through, with an emphasis that both LVRT and HVRT performance should be tested during the design phase of a facility using validated IBR unit models based on type-testing.

R4: In the Technical Rationale, the drafting team explains that due to lower system inertia "a wider frequency ride-through capability for IBR **may** be required to avoid the risk of widespread tripping." Can the drafting team cite more specific reasoning or data to support the expansion of the frequency ride-through capability requirement to the range of 64Hz to 56Hz, well beyond the IEEE 2800-2022 standard frequency ride-through requirement and the capabilities of many legacy IBRs?

The proposed 6-second frequency ride-through capability requirement for the ranges of 61.8Hz to 64Hz and 57Hz to 56Hz does not align with the requirements on the rest of the BES. For the foreseeable future, synchronous generators will continue to be a significant part of the grid. It is a well-established fact that such large electric machinery, which are directly connected to the grid, cannot be exposed to such large variations in frequency. Therefore, it does not seem reasonable to ask IBRs to go to such extremes.

R5: We fail to see the value of requirement R5 given the other ride-through requirements, and it's unclear to us how an entity is to determine if the subject switching event is initiated by a fault or not. Additionally, we don't believe the language in R5.1. regarding equipment tripping to prevent equipment damage is reasonable or auditable. We recommend Requirement R5 is removed.

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5

Answer	No

Document Name	
Comment	

No, Invenergy disagrees with the proposals for including IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in Requirements R3, R4, and R5. We offer the below comments regarding these Requirements:

R3: Can the drafting team provide data that demonstrates observed overvoltages during recent System events were of the TOV magnitudes and durations defined in Attachment 2 Table 3? TOVs of such scale are primarily due to the following three scenarios: 1) a lightning strike on the nearby transmission system, 2) transmission line switching transients, and 3) resonant phenomena like voltage magnification due to shunt capacitor switching on the transmission system. Measures are already in place to mitigate such events, including but not limited to proper insulation coordination and substation design, metal oxide varistors, and proper capacitor bank switching of transmission level shunt capacitors (e.g. synchronous switching or use of pre-insertion resistors to mitigate voltage magnification to the extent possible).

To support our statement above, consider an often-quoted document to support these TOV requirements in the NERC Odessa Disturbance Texas Events: May 9, 2021 and June 26, 2021 Joint NERC and Texas RE Staff Report, Dated September 2021. A detailed read of the section that is entitled Inverter Transient AC Overvoltage Tripping Persists identifies poor coordination of controls and protection as the primary driver of these events, rather than TOV conditions at the point of measurement due to switching transients or any type of resonance. What the report explains is that in some cases the IBR units force maximum reactive power output during a fault to push the network voltages up, then once the fault clears they do not pull back on the reactive power injection quickly enough, which leads to an RMS over-voltage (not switching event TOV) at the terminals of the IBR unit, and thus the IBR units tripped. This is solved by 1) proper controls and protection coordination, 2) proper IBR plant design, and 3) proper evaluation of the LVRT and HVRT ride-through capabilities of the IBR plant during the design phase of the plant.

R3 should be removed, and the focus placed on low voltage ride-through and high voltage ride-through, with an emphasis that both LVRT and HVRT performance should be tested during the design phase of a facility using validated IBR unit models based on type-testing.

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The proposed 6-second frequency ride-through capability requirement for the ranges of 61.8Hz to 64Hz and 57Hz to 56Hz does not align with the requirements on the rest of the BES. For the foreseeable future, synchronous generators will continue to be a significant part of the grid. It is a well-established fact that such large electric machinery, which are directly connected to the grid, cannot be exposed to such large variations in frequency. Therefore, it does not seem reasonable to ask IBRs to go to such extremes.

R5: We fail to see the value of requirement R5 given the other ride-through requirements, and it’s unclear to us how an entity is to determine if the subject switching event is initiated by a fault or not.

Additionally, we don’t believe the language in R5.1. regarding equipment tripping to prevent equipment damage is reasonable or auditable. We recommend Requirement R5 is removed.

Likes 0	

Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	

Comment

1 AES CE agrees that such performance criteria in R3, R4, and R5 needs to be included, but requests modifications and clarifications as requested below:

2· The language in R3 and R5 relating to “switching events” is difficult to track from the GO perspective. If such an event occurs at the Transmission Operator (TOP), we may not be aware of the need to track and assess our IBR performance as applicable to PRC-029 unless notified by the TOP. If a performance issue with an IBR is identified we would need to be informed by the TOP that a switching event occurred to assess applicability to PRC-029.

3 Please update the technical rationale to clearly state that the 5 Hz/second criteria in R4 aligns with IEEE2800.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

These requirements would be a huge expense for sites that currently don't have frequency response capabilities and there is a strong possibility that many would not be capable of meeting based on manufactures. It will not be financially feasible for all project owners to support this change.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response	
George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Invenergy's comments for this question.	
Likes 0	
Dislikes 0	

Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and North American Generator Forum (NAGF) on question 3	
Likes 0	
Dislikes 0	

Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
R5 , First time seeing this type of protective setting, unsure as to whether or not any documentation exists or protective settings currently exist in our fleet for this.	

M5 ,

Will the PC's be communicating in writing to the Generator Owner every time there is a disturbance with the request for this data. How long will the data need to be held?

The values for ride through are different from PRC-24. All current generation sites have targeted to comply with the curve given in PRC-24. The basis of moving these protective curves are unclear.

Likes 0	
Dislikes 0	

Response

Joy Brake - Nova Scotia Power Inc. - NA - Not Applicable - NPCC

Answer	No
Document Name	

Comment

Yes, they are needed but the understanding of what those criteria should be is not evolved sufficiently at this time. Also, large scale EMT network models are not of sufficient quality to assess the criteria in the design phase.

For example, if RoCoF is for a time period of greater than or equal to 0.1 second, it leaves the choice of sample time to the user. The plant can take the 100ms for calculations and meet the criteria. The System Operator criteria may calculate RoCoF over 500ms (as we do) and would see the plant as not meeting criteria for the same event.

The proposed RoCoF of 5Hz/s is higher than IEEE1547 Category I, II and III. Transmission Wind turbines and their capabilities are often the same as DER plants. A transmission facility just has a lot more of them. That said, we are looking to introduce higher RoCoF for DER as they may be vulnerable as we transition to a very high IBR grid.

RoCoF is not calculated during the fault occurrence and clearance? The standard would only apply for loss of a source of generation without a fault? For loss of our tieline for a fault it would not apply but loss of tieline for neighbouring RAS action it would? It is most needed when there is a fault. For a fault, we are also losing the older wind MW as they go into momentary cessation during the fault making the generation loss greater. For simple loss of supply, a high IBR grid is stronger than for a loss of supply due to fault. We apply RoCoF criteria during a fault. Our current criteria for transmission design is 2.4 Hz/s calculated over 500ms. Our current design criteria for generation facilities ride through is 4Hz/s. But it is under review in EMT studies. We do not use rolling average at this time as it is difficult to accurately calculate in PSSE. We hope to be able to move to rolling average as we increase our use of PSCAD study results for operational studies.

How does it align with the RoCoF criteria for synchronous plants? We are surveying our existing thermal plants and it is still a bit of an unknown in some areas. Our current criteria of 4Hz/s applies to all generating facilities.

Likes 0	
Dislikes 0	

Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

The NAGF provides the following comments:

a. Requirement R3 – the NAGF notes that GOs do not have knowledge of BPS/BES "switching events" and requests that the Drafting Team (DT) consider adding a requirement for the TO/TOP to notify the GOs of such events.

b. Requirement R4:

i. The term "applicable IBR" needs clarification.

ii. Request additional clarification/justification regarding the proposed 5 Hz/second threshold.

iii. The NAGF requests clarity on how to test compliance with the TOV Ride-Through requirement during study or plant IBR design phase.

c. Requirement R5:

i. Same concern as identified for R3

ii. The requirements for phase angle shift of 25 degrees should allow IBR tripping if the post-fault system condition is drastically changed and the device protection is activated.

Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	

- WEC Energy Group disagrees with R3. FERC Order 901 calls for addressing system disturbances. A switching event does not qualify as a system disturbance. In addition, disturbance events summarized this as an anti-islanding protection issue and therefore it should be stated in R3 to reduce confusion. If the SDT decides to keep R3, then R3 should include following text, "unless a documented equipment limitation exists in accordance with Requirement R6."

- WEC Energy Group agrees with inclusion of R4 with following exception: R4 should include following text, “unless a documented equipment limitation exists in accordance with Requirement R6.”
- WEC Energy Group agrees with inclusion of R5 with following exceptions:
  - R5 should include following text, “unless a documented equipment limitation exists in accordance with Requirement R6.”
  - The industry term is known as PLL Loss of Synchronism and is identified as such in disturbance reports. Therefore, R5 should adopt the same to reduce the confusion.

Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy recommends the implementation of EEI and NAGF comments.

Duke Energy also recommends, if not already considered, to verify with OEMs that the inverters can satisfy Att 2. Figure 3 does not align with IEEE 2800 Figure 14; again, making compliance with both requirements more complicated.

The controls only respond to voltage and therefore will have no context of the initiating event as could be implied by the statements in R3 and R5. Recommend adding an exception to R3 worded in a similar format to the exception stated in 5.1.

Likes 0	
Dislikes 0	
Response	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	

R3-5: R6 should apply to R1-R5 to account for equipment limitations that may also apply to R3-R5. Recommend similar language included in R1 and R2 is added to R3-5:

“…unless a documented equipment limitation exists in accordance with Requirement R6.”

Recommend that there be no requirement to document limitations on legacy equipment and that this standard focuses on equipment brought into service after the implementation date.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	No
Document Name	

Comment

These requirements would be a huge expense for sites that currently don't have frequency response capabilities and there is a strong possibility that many would not be capable of meeting based on manufactures. It will not be financially feasible for all project owners to support this change.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	No
Document Name	

Comment

No technical expertise to comment.

Likes 0	
Dislikes 0	

Response

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers

Answer	No

Document Name	
Comment	
Vistra agrees with AEP.	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
On behalf of the SERC Generator Working group: Apply the R1 and R2 phrase "…unless a documented equipment limitation exists in accordance with Requirement R6" to R3, R4, and R5 in addition to what is currently proposed in R1 and R2. For R3 and R5, the GO will not know an over-voltage or phase jump is the result of a non-fault switching event, so is the GO expected to treat all over voltage and phase jump events as non-fault events.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
R5.1: This requirement is beyond the purpose of the standard, which is to establish Frequency and Voltage Ride-through Requirements for Inverter - Based Generating Resources and should be removed.	
Likes 0	
Dislikes 0	

Response	
Carey Salisbury - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	

For R3 and R5, the GO will not know an over-voltage or phase jump is the result of a non-fault switching event, so is the GO expected to treat all over voltage and phase jump events as non-fault events.

Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 5	
Answer	No
Document Name	
Comment	

There are several concerns with the equipment limitation exemption language in the draft of R6, and such exemptions not being allowed for R3 and R5. To justify R6 only allowing an equipment limitation exemption for existing resources to R1 and R2, and not the other requirements of PRC-029, the NERC drafting team's technical rationale document points to FERC Order 901:

The objective of Requirement R5 [sic] is to ensure legacy IBR may need to obtain an exemption to the voltage ride-through requirements if hardware replacements or other costly upgrades would be necessary to comply with Requirements R1 or Requirement R2… FERC Order No. 901 states that this provision would be limited to exempting "certain registered IBRs from voltage ride-through performance requirements." This is the reason that no similar provisions are included for exemptions for frequency, rate-of-change-of-frequency (ROCOF), phase angle change ride-through requirements.

First, the R6 equipment limitation exemption should also apply to R3, which requires ride-through for "a transient overvoltage as a result of a switching event whereby instantaneous voltage at the high-side of the main power transformer exceeds 1.2 per unit." As NERC notes, FERC Order 901 directed NERC that existing resources can have equipment limitation exemptions from voltage ride-through requirements, and remaining online during transient over-voltage is clearly a voltage ride-through requirement. Transient over-voltage can damage equipment, so allowing IBRs to protect against this damage is consistent with FERC's intent in Order 901 to only allow tripping that is necessary to protect equipment. Moreover, in many cases making existing equipment better able to withstand transient overvoltages would require replacing or modifying hardware.

For similar reasons, an equipment limitation exemption for existing resources should also apply to R5, which requires ride-through for voltage phase angle changes of less than 25 degrees. FERC Order 901 directed NERC that existing resources can have equipment limitation exemptions from voltage ride-through requirements, and remaining online during voltage phase angle changes should be interpreted as part of voltage ride-through requirements. Remaining online during phase angle changes of less than 25 degrees could be a problem for existing generators, particularly wind generators as phase angle changes can impose mechanical stresses on the wind turbine's rotating equipment. Not allowing an equipment limitation exemption for existing generators under R5 is particularly problematic as it is not typically feasible to retrofit existing wind turbines to increase their ability to withstand mechanical stresses due to phase angle changes. In such cases, making existing equipment better able to withstand voltage phase angle changes would require replacing or modifying hardware. Phase angle changes can damage equipment, so allowing IBRs to protect against this damage is consistent with FERC's intent in Order 901 to only allow tripping that is necessary to protect equipment.

Moreover, a contextual reading of Order 901 indicates FERC was mostly focused on limiting equipment limitation exemptions to existing generators that would have to physically replace or modify hardware, and not strictly limiting such exemptions to a narrow reading of what constitutes voltage ride-through requirements. Paragraph 193 in its entirety, and particularly the first sentence, explain that FERC's intent was focused on exempting existing resources that would have to physically replace or modify hardware: "we agree that a subset of existing registered IBRs –typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements directed herein." FERC continued by directing that "Any such exemption should be only for voltage ride-through performance for those existing IBRs that are unable to modify their coordinated protection and control settings to meet the requirements without physical modification of the IBRs' equipment."{C}[1] As explained above, equipment limitation exemptions for R3 and R5 are likely necessary to ensure some existing generators do not have to physically replace or modify hardware, and thus such exemptions are consistent with FERC's directive in Order 901.

Finally, R6 equipment limitation exemptions should be allowed for resources with signed interconnection agreements as of the effective date of the Standard, instead of resources that are in-service as of that date. Resource equipment decisions are typically locked down at the time the interconnection agreement is signed, and a change in requirements after that point can require a costly change in equipment or settings that may also trigger a material modification and resulting interconnection restudies. The implementation plan for PRC-029 indicates that the effective date for the Standard will be the first day of the first quarter six months after FERC approval. Many resources take significantly longer than that to move from a signed interconnection agreement to being placed in service, so it makes more sense to allow R6 equipment limitation exemptions for resources that have a signed interconnection agreement as of the effective date of the Standard.

{C}[1]{C} Order 901, https://www.ferc.gov/media/e-1-rm22-12-000, at paragraph 193

Likes 0	
Dislikes 0	
Response	
Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

A premise of R3 is knowing of a transient OV, due to a switching event on the transmission system. The Generator Owner is not going to have the intelligence to know if a transient OV is due to a switching event. So, is the GO expected to treat all OV events as non-switching events?

1. Requirement R3: The Transient Overvoltage Ride-Through requirement is just not ready to be included in a regulatory standard. The measure for this requirement is based on actual recorded data. The existing facilities may not even have recording equipment in place to measure switching transients. The IEEE P2800.2 WG has also struggled to come up with a Design Evaluation procedure to show that the plant would be able to ride-through the specified TOV ride-through requirements.
2. Requirement R4:
    - The intent of “continue to exchange current” is understood, however, the requirement is vague. During frequency excursion events, it is necessary that IBR adjusts active power output in response to frequency deviation. But these details are not necessary in NERC standards, currently. The IBR that “continues to exchange current” but not based on frequency deviation, would comply with the standard requirements, which is not ideal. The TP/PC is expected to specify IBR performance during abnormal system frequency. Hence, the requirement should read as following: Each GO or TO of an applicable IBR shall ensure each IBR remains electrically connected and continues to exchange current **as specified by TP or PC** during a frequency excursion event……
    - Why is there no exception for Volts/Hz limit? This could be an issue for type III WTG and transformer within the plant. The frequency ride-through requirement in the IEEE Std 2800 recognizes Volts/Hz limitation.
3. Requirement R5:
    - Consider revising to read as follows: Each GO or TO of an applicable IBR facility shall ensure that each IBR remains electrically connected and continues to exchange current during non-fault switching events where the instantaneous change in positive sequence voltage phase angle is less than or equal to 25 electrical degrees at the high-side of the main power transformer.
    - Has the SDT discussed how to measure “instantaneous” phase angle jump based on recorded data?
    - Part 5.1 is not necessary. The IBR may not trip because it measured phase angle jump of greater than 25 electrical degrees but may trip due to affects of such a jump in phase angle. Not sure how to even prove that equipment was at risk or not.
    - For R5, the GO will not know if a phase jump is the result of a non-fault switching event, so is the GO expected to treat all phase jump events as non-fault switching events?
    - In R5, what happens if an IBR trips due to phase angle jump while the frequency and voltage remain in the continue to operate range? IBRs will not know whether the system has experienced a fault or not.
4. Attachment 3:
    - Why does the SDT require more stringent ride-through capability compared to the IEEE Std 2800? If a certain interconnection requires stringent ride-through requirement then it should only be required for that interconnection. There is no need to extend the stringent requirements of one interconnection to all interconnections. Such an approach is implemented in the PRC-024, PRC-006, etc. Additionally, the PRC-006 specifies boundaries between which the frequency needs to remain while simulating and designing UFLS scheme. The IBR frequency ride-through coordinated with boundaries in PRC-006 should be enough.
    - Table 4:
        - Not sure what is implied by “average system frequency”. The term “average” makes sense when associated with ROCOF but not with frequency.
        - ≥64 should be >64
        - ≥61.8 should be >61.8
    - Note 1 is not necessary. Which measurement is taken on each phase?
    - Note 2: Consider replacing with following: Frequency is measured over a period of time, typically 3-6 cycles.

- Note 3: not sure which "control settings" are referred here. Consider the following from PRC-024: Instantaneous trip settings based on instantaneously calculated frequency measurement is not permissible.
- Note 5: Why did the SDT specify 15-min time period instead of 10-min time period in the IEEE Std 2800.

ROCOF and phase angle jumps:

- Some legacy IBRs have technical limitations that will prevent them from riding through ROCOF less than or equal to 5 hz / second or phase angle jumps less than 25 electrical degrees. Such IBRs need the ability to seek an exemption for these requirements.Note: ERCOT has questioned the validity of how ROCOF and phase angle jumps are measured, and whether the 5 hz / second and 25 electric degree values are accurate.
- R5 specifies that IBRs must ride through phase angle jumps initiated by **non-fault** switching events and are changes of less than 25 electrical degrees. There is an issue Southern Company has encountered on NOGRR245. ERCOT has proposed that IBRs not trip for any ROCOF or phase angle jumps during **fault** conditions. It is an understanding that IBRs should ignore ROCOF and phase angle jump values during fault conditions. Southern Company would support similar fault language in PRC-029-1, but a technical exemption would be required because some legacy IBRs are unable to distinguish between a fault and non-fault condition.

R6.1.2 discusses *"aspects of VRT requirements that the IBR would be unable to meet".* This language could be clearer by requesting the IBR to identify actual VRT capabilities.[A1]

M6 requires evidence of equipment limitations prior to the effective date of the standard. This could be extremely challenging to meet.

Finally, Southern Company supports NAGF comments.

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	

Comment

Rwquirement 3

PG&E believes specific requirements for the inverter capabilities should be removed from the NERC standard and left to the IEEE 2800-22 standard for inverter specifications. The utility relies on RMS measurements and does not have a means to accurately measure transient over-voltage conditions for protective relays; therefore, it would be extremely difficult for the entity to prove its compliance.

Requirement 4

Frequency ride-through limits have been raised considering that IBRs can continue to generate. For synchronous machines, it is not possible to have such a wide frequency range (as per attachment 3 copied below). When the system has majority of IBRs, the effect on synchronous machines with such wide frequency variations is unknown. Also, it would affect the underfrequency load shedding schemes.

PG&E has the following questions for the SDT to consider: Should there be separate ride through limits for Grid Forming inverters and Grid Following inverters? Would higher penetration of IBRs affect the allowable frequency ranges?

Requirement 5

PG&E believes specific requirements for the inverter capabilities should be removed from the NERC standard and left to the IEEE 2800-22 standard for inverter specifications.

PG&E has the following question for the SDT: how do we set relays or trigger a DFR for a switching/non-fault event to show compliance with the requirement?

Likes 0	
Dislikes 0	

Response

Mark Flanary - Midwest Reliability Organization - 10

Answer	No
Document Name	

Comment

See comments below under question 4.

Likes 0	
Dislikes 0	

Response

Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	2020-02_EPRI Comments on Draft NERC PRC-029 (IBR ride-through) Reliability Standard.pdf

Comment

Likes 0	
Dislikes 0	

Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	

We agree that PRC-024 standard should remain (enforced) because this will also help in ensuring the reliability of the Bulk Power System.

Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

The IESO recommends the following modifications to the text improve clarity or to better convey intent.

With regards to R4:

"…continues to exchange current during a frequency excursion event whereby the **system** frequency remains within the "no trip zone" according to…"

This suggestion would differentiate the actual system frequency from, say, the frequency measurement as 'seen' by the PLL or other parts of the controls.

With regards to 5.1

As commented above, IESO believes 'not tripping except to provide equipment protection' warrants a dedicated Requirement, which may be referred to the context of other requirements, such as performance during phase angle jumps.

Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	
Response	
Michael Brytowski - Great River Energy - 3	

Answer	Yes
Document Name	
Comment	

Comments: Initial review indicates the proposed requirements R3, R4 and R5 align with IEEE 2800 which we support.

R3: we suggest adding to attachment 2 how the instantaneous transient overvoltage should be calculated (such as what the pu base? and the minimum sampling rate?)

Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	

FirstEnergy has no issue for the direction of these requirements.

Likes 0	
Dislikes 0	
Response	

Stefanie Burke - Portland General Electric Co. - 6

Answer	Yes
Document Name	
Comment	

PGE supports EEI's comments but in addition would add clarification: For the requirement to say "may trip, but shall only trip to prevent equipment damage" does not provide clear direction. If the IBR can stand a 30 electrical degree change, is it acceptable to trip at 25.0 to prevent equipment damage? It would be preferrable to provide a safety margin before reaching the damage point. Or, is this stating that the IBR wait until 30.0 electrical degrees is reached before taking action? What is the measure for making sure an IBR does not trip at 25.0 or above except to protect the equipment? If there is nothing particularly harmful about tripping an IBR above 25.0, why not indicate that above 25.0 is not a "Must Trip Zone/Criteria"?

Likes 0	

Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
R3: we suggest adding to attachment 2 how the instantaneous transient overvoltage should be calculated (such as what the pu base? and the minimum sampling rate?)	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS supports the following comments that were submitted by EEI on behalf of its members:	

EEI supports the proposal to include IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in PRC-029-1 Requirements R3, R4, and R5. However, the following phrase "of an applicable IBR" should be removed from R3, R4 and R5. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposal to include IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in PRC-029-1 Requirements R3, R4, and R5. However, the following phrase "of an applicable IBR" should be removed from R3, R4 and R5. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Maozhong Gong - GE - GE Wind - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	

Comment	
But we need to consider old units, please see the additional comments below.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
R3: MP agrees with the NSRF's comments on defining the transient overvoltage calculation method. MP also suggests defining the term "current block mode."	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG supports IESO's comments.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	

See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
However, please verify the ROCOF with regards to how FR data at the IBR Unit level (per the definitions proposed by 2020-06) is required to be captured (Per proposed PRC-028-1). Note that PRC-002-4 and -5 have ROCOF triggers for recording that are significantly different than 5 Hz/second. Measure 4 of PRC-029-1 has a reference to a Planning Coordinator's area but Requirement 4 has no such limitation or uses Planning Coordinator within the language. It appears that the stated ROCOF is high based on IRPT reports (https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf). And the ROCOF definition is different from said report by the IRPTF.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
NextEra aligns with EEI's comments: EEI supports the proposal to include IBR transient overvoltage, frequency, ROCOF, and instantaneous voltage phase-angle jump ride-through performance criteria in PRC-029-1 Requirements R3, R4, and R5. However, the following phrase "of an applicable IBR" should be removed from R3, R4 and R5. Applicability is defined in the Applicability Section of the standard and anything more is unnecessary and redundant.	
Likes 0	
Dislikes 0	
Response	

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

ERCOT joins the comments of the IRC SRC and adopts them as its own in addition to the following comments, except to the extent of any specific differences between the SRC comments and the following comments from ERCOT.

Footnote 2 is not clear as to whether RoCoF measurement should begin immediately or upon fault clearing. IEEE 2800.2 discussions are heading in a direction that would indicate that during fault occurrence, clearance, and recovery back to a steady-state operating point, failure to ride through should only be allowed if the voltage is beyond the requirement (i.e., the unit should not trip due to any perceived RoCoF during the entire disturbance and recovery period). This is similar for phase angle jump.

Requirement R4 may need to include language similar to that found in Requirement R5, Part 5.1 to ensure RoCoF is set to the equipment capability and is not arbitrarily set at 5 Hz/s. ERCOT also notes that the IEEE 2800-2 drafting team is identifying that there should be agreement between unit owners and planners/operators on how to measure RoCoF (at what time points, greater than or equal to .1 second) to ensure consistency in testing, model validation, application, and performance evaluation. Otherwise, such a requirement may create confusion or otherwise be unenforceable. IEEE 2800-2 also identifies the potential need for higher RoCoF requirements, which may be appropriate in smaller Interconnections.

The current language in Requirement R5 excludes voltage phase angle change of exactly 25 degrees, which is included in IEEE2800 requirements:

SDT's proposed language:

"Each Generator Owner or Transmission Owner of an applicable IBR shall ensure each IBR remains electrically connected and continues to exchange current during instantaneous positive sequence voltage phase angle changes **that are initiated by non-fault switching events on the transmission system and are changes of less than 25 electrical degrees at the high-side of the main power transformer.**"

ERCOT's proposed language:

Each Generator Owner or Transmission Owner of an applicable IBR shall ensure each IBR remains electrically connected and continues to exchange current during instantaneous positive sequence voltage phase angle **changes of 25 electrical degrees or less at the high-side of the main power transformer that are initiated by non-fault switching events on the transmission system**.

Finally, ERCOT believes that under the Violation Risk Factor guidelines, Requirements R3, R4, and R5 should have a VRF of High as they are requirements "**that, if violated, could directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures** . . . ."

Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI comments	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	

Answer	Yes
Document Name	
Comment	

Overall, we at ACES support Requirements R3 through R5; however, we have a minor concern with the wording of Requirement R3, Option 2. Specifically, we have concerns with the requirement to “restart current exchange within 5 cycles of the instantaneous voltage falling below (and remaining below) 1.2 per unit.” For how long of a duration should the instantaneous voltage remain below 1.2 p.u. to trigger the 5 cycles wherein the IBR must resume current exchange? We recommend that the SDT consider adding a time component to the return from the transient overvoltage condition.

Likes 0	
Dislikes 0	
Response	

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2

Answer	Yes
Document Name	
Comment	

Southwest Power Pool joins the ISO/RTO Council Standards Review Committee comments.

Likes 0	
Dislikes 0	
Response	

Darcy O'Connell - California ISO - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee

Answer	Yes
Document Name	
Comment	

Initial review indicates the proposed requirements R3, R4, and R5 align with IEEE 2800, which the SRC supports.

The SRC recommends the following modifications to the text to improve clarity and to better convey the intent of the standard.

Recommended changes to R4:

"…continues to exchange current during a frequency excursion event whereby the **system** frequency remains within the "no trip zone" according to…"

This revision would clarify that the actual system frequency is the relevant measurement instead of the frequency measurement as 'seen' by the PLL or other parts of the IBR control system.

Recommended changes to R5.1

As noted above, the SRC believes 'not tripping except to provide equipment protection' warrants a dedicated Requirement, which may be referred to in the context of other requirements, such as performance during phase angle jumps.

Likes 0	
Dislikes 0	

Response

Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting

Answer	Yes
Document Name	

Comment

Yes. The SDT should consider citing IEEE 2800-2022 directly in the standard and consider using the IEEE 2800-2022 ride-through requirements as a means to comply with Requirements R1-R5 instead of using Attachment 1 of the standard.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Brittany Millard - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Campbell - David Campbell On Behalf of: Natalie Johnson, Enel Green Power, 5; - David Campbell	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shonda McCain - Omaha Public Power District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katrina Lyons - Georgia System Operations Corporation - 4	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wesley Yeomans - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Wendy Kalidass - U.S. Bureau of Reclamation - 5

Answer	
Document Name	

Comment

Not Applicable to Reclamation.

Likes 0	
Dislikes 0	

Response

Imane Mrini - Austin Energy - 6, Group Name Austin Energy

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

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

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

Answer	
Document Name	

Comment

The proposed PRC-029 seems vague and does not specify what size IBR would applicable. If it is below the 75MVA aggregate, then I believe that would cause undue burden on utilities to meet.

Likes 0	
Dislikes 0	

Response

Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting

Answer	
Document Name	

Comment

Attachment 1 needs a few corrections.

- Figures 1 and 2 use a logarithmic time scale for the Time x-axis. This should be updated to be a regular non-logarithmic time scale.
- There are numerous inconsistencies in this standard language and Attachment 1 when compared to IEEE 2800. These should be considered and reviewed for clarity and completeness in the standard. The option to cite IEEE 2800-2022 and use the requirements in the IEEE 2800-2022 directly should be allowed over just the use of Attachment 1 (give each GO/TO the ability to use either of these guides to base their performance off of).
    - IEEE 2800 identifies the following items, but the standard does not support. Clarification/review should occur for each of these items:
        - Exceptions for Negative-sequence voltage exceeding thresholds
        - IEEE 2800 recognizes Volts/Hz limitations, but the standard does not.
        - IEEE 2800 recognizes 500kV system voltages are actually operated in the range of 525kV and therefore has equipment rated to 550kV. These 500kV operating conditions should be considered in the standard.
        - In IEEE 2800 the frequency ride-through criteria defines 10-minute time periods whereas the standard defines them in a 15 minute time period (Table 4 of Attachment 3). This should be clarified and identified.

The standard is quite vague in terms of technical limitations and documentation exemptions to the requirements. Experience has shown that this is a highly nuanced and difficult consideration. There is no language focused on software versus hardware limitations and what is allowed/expected. This could lead to inconsistent, subjective auditing practices rather than clear objective requirements and auditing.

Likes 0	
Dislikes 0	

Response

Darcy O'Connell - California ISO - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee

Answer	
Document Name	

Comment

The SRC requests several enhancements to **PRC-029**.

1. **Clarify and emphasize that documented equipment limitations under Requirement R6 must not be construed to be complete exemptions from the Requirements of PRC-029.** If entities are unable to ride-through portions of the ride-through curve, this should not automatically exempt them from complying with the balance of the ride-through curve as described in the Technical Rationale. While this is clearly expressed in the Technical Rationale for Requirement R6 (page 9), this point needs to be brought out more clearly in the PRC-029 standard itself.
2. **Expand PRC-029 to require that Corrective Action Plans be developed and implemented to remove equipment limitations within a specified timeline or require a** technical justification that addresses why corrective actions will not be applied nor implemented.
3. PRC-029 will need to explicitly require any new inverter/controller replacing older equipment to be compliant with PRC-029 rather than set to original equipment specification.
4. Applicability:In Introduction, Section 4.2.2, it is not obvious what aspect of 'IBR Registration Criteria' makes an IBR an 'applicable' IBR – is it simply that an IBR meets NERC Registration Criteria? This bullet point should be elaborated upon to ensure clarity.
5. Event-Based Standard: The SRC has concerns that this standard is an event-based standard that does not necessarily provide an assurance of reliability before events occur, such as would be provided by having an engineering analysis or results from bench-testing and real-time simulations of control equipment that indicate that successful ride through of prescribed disturbances is expected.
6. Without disturbance events that show whether IBRs perform properly, there is no way to determine if an IBR is compliant with the standard. At a minimum, the measures (e.g, M2-M5) should be extended to indicate that a statement that no such events are known to have occurred will qualify as evidence of compliance.
7. Presentation of Ride-Through Ranges: The intended ride-through requirements would be made more clear if the 'minimum ride-through times' were associated with precisely stated, *non-overlapping ranges* of voltages or frequencies, such as in the example 'Table 2' provided by the SRC in its comments above.
8. Nominal Voltages: Note #4 of Attachment 1 would be clearer if the 'nominal' system voltage values were listed as they are in Attachment 2 of PRC-024-3, i.e., "(e.g., 100 kV, 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 400 kV, 500 kV, 765 kV, etc.)"
9. Harmonize Tables, Figures, Requirements: The voltage/frequency excursion levels and the associated minimum ride-through times for all tables, figures, and any associated performance requirements that modify the requirements should be carefully reviewed and harmonized. There are presently some conflicting entries in the tables/figures.

10. PRC-029 introduces new terms. The drafting team should consider using these new terms in PRC-024 for consistency. The ranges in these definitions may be specific to IBRs due to their unique performance characteristics, but these regions serve the same purpose for synchronous generators.
    i. Term(s):
    ii. Continuous Operating Region – The range of voltages, measured at the high-side of the main power transformer, that are ≥ 0.9 per unit and ≤ 1.1 per unit.
    iii. Mandatory Operating Region – The range of voltages, measured at the high-side of the main power transformer, that are > 0.1 per unit and < 0.9 per unit – or – > 1.1 and ≤ 1.2 per unit.
    iv. Permissive Operating Region – The range of voltages, measured at the high-side of the main power transformer, that is ≤ 0.1 per unit.
11. There does not seem to be a direct explanation of how these new terms used in the Requirements are applied in Attachment 1, where the ranges for “No-Trip” and “Must-trip” are shown. the only mention of these terms in Attachment 1 appears to be in bullets 8, 9, and 10 where one or two Regions are mentioned and assumed to be understood. Additionally, these terms are not used consistently throughout the standard, as these terms are defined as “Operating Regions,” but frequently appear in the standard as “Operation Regions.” The SRC recommends that the SDT standardize on a consistent format for these terms.

R1. Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that each IBR remains electrically connected and continues to exchange current in accordance with the no-trip zones and operation regions as specified in Attachment 1

Attachment 1

8. The specified duration of the Mandatory Operation Regions and the Permissive Operation Regions in Tables 1 and 2 is cumulative over one or more disturbances within a 10 second time period.

Likes 0	
Dislikes 0	

Response

Mark Flanary - Midwest Reliability Organization - 10

Answer	
Document Name	

Comment

Requirements R1, R2, R3, R4, and R5 and associated Measures do not make it clear whether equipment settings or configurations that render a facility unable to meet the performance requirements constitute a non-compliance prior to the occurrence of an event where the facility fails to meet the performance requirements. An understanding of these requirements as event-based (as described in the current draft of the PRC-029-1 Technical Rationale) would only partially accomplish the risk objectives described in the SAR and in FERC order 901 as many events would not be prevented. This is particularly concerning for frequency excursion events (R4) as these events are relatively infrequent and yet widespread, potentially resulting in the failure of a multitude of IBRs to meet the performance requirements if frequency trip settings are not evaluated preemptively. As such, these requirements should make it clear that facilities are to be configured to meet performance requirements and that the relevant equipment settings should be available as evidence to show compliance.

If there are portions of the performance criteria in this standard that equipment owners cannot be expected to meet through assessment of equipment settings in the absence of an event, those portions should be addressed in separate requirements that specify corrective actions to be performed following an event rather than identify non-compliance at the time of the event.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	

Comment

Attachment 1, Part 2b. I assume that “ESS” means Energy Storage System? Please document or clarify.

Part 7 “ … trip …” again. Same question as in comment 2 above. The second sentence is also unclear. What is “the 10-second time period”? Is this phrase identified in Parts 8 and 9? If so, please define it before first use and use the same phrase subsequently.

Attachment 2 Part 3 “ … trip …” again. Same question as in comment 2 and Attachment 1 Part 2b above.

Attachment 3, Table 4 Part 2. I agree with averaging frequency over a set time period. But 3 cycles seems rather short to assure a reasonable frequency value, especially during fault conditions. IEEE 2800 says “… at least 0.1 sec” [6 cycles] for ROCOF, and that is probably a good target for frequency also.

Table 4 and Part 4 “ … trip …” again. Same question as in comment 2 and Attachment 1 Part 2b and 3 above.

Likes 0	
Dislikes 0	

Response

John Pearson - ISO New England, Inc. - 2

Answer	
Document Name	

Comment

The new or modified terms should define what the “voltage” is, RMS, Positive Sequence? Instantaneous? Etc. for Continuous Operating Region, Mandatory Operating Region and Permissive Operating Region.

In Attachment 1, bullet 3 is problematic, basing the applicable table based on direction by the Transmission Planner needs to have a specific requirement describing how that would be done. Bullet 4 is also problematic for the same reason. Bullet 8 – Mandatory Operation Regions should conform with IEEE 2800 7.2.2.4 for consecutive disturbances, and differentiate from dynamic voltage oscillations. Bullet 9 should also conform to IEEE 2899 7.2.2.4.

Likes 0	
Dislikes 0	

Response

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2

Answer	
Document Name	

Comment

Southwest Power Pool joins the ISO/RTO Council Standards Review Committee comments.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators

Answer	
Document Name	

Comment

- It is the opinion of ACES that Section 4.2 should be modified to utilize the registration criteria as defined in the latest revision of the NERC Rules of Procedure.

Thus, we recommend the following revisions to Section 4.2:

4. Applicability:

4.1 Functional Entities:

4.1.1 Generator Owner that owns an applicable facility in Section 4.2.1.

4.1.2 Transmission Owner that owns an applicable facility in Section 4.2.3.

4.2 Facilities:

4.2.1 Either of the following Inverter-Based Resource (IBR)1 types:

4.2.1.1 BES IBR

4.2.1.2 non-BES IBR that is:

4.2.1.2.1 Connected to the Bulk Power System, and

4.2.1.2.2 Meets the criteria for a Category 2 GO facility.

4.2.2 High-voltage Direct Current (VSC-HVDC) Transmission facilities that serve as a dedicated connection for an Inverter-Based Resource meeting the criteria of 4.2.1.1

- Transmission is a defined term in the NERC Glossary of Terms. As it is currently defined, this term does not specify a voltage threshold for its applicability; therefore, we recommend capitalizing all uses of the word “transmission” within PRC-029-1 for the sake of clarity.

Likes 0	
Dislikes 0	

Response

Katrina Lyons - Georgia System Operations Corporation - 4

Answer	
Document Name	

Comment

GSOC supports Georgia Transmission Corporation (GTC) Comments.

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	
Document Name	

Comment

See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See EEI comments	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

ERCOT joins the comments of the IRC SRC and adopts them as its own in addition to the following comments, except to the extent of any specific differences between the SRC comments and the following comments from ERCOT.

The proposed changes to PRC-024 create a reliability gap, as Type 1 and Type 2 wind turbines are not synchronous machines and would therefore no longer be required to comply with PRC-024 but are not included in PRC-029 because they are not IBRs. The SDT should consider including a specific requirement in PRC-024 or PRC-029 that addresses this technology and requires these types of units to try to meet requirements up to their equipment limitations, to notify their PC/TP/RC/TOP of such limitations, and to reflect any such limitations in their dynamic models. This will ensure that the PC/TP/RC/TOP can incorporate the expected performance of these units in their studies.

ERCOT agrees with the SDT’s overall approach of ensuring that PRC-029 is clearly a performance-based standard. However, the standard is not entirely clear on this point, as the Time Horizon is “operations assessment” instead of “Real-time Operations.” Additionally, the standard generally uses a structure of ‘owners…shall… ensure that’ instead of an ‘owners….shall.. perform’ structure. Structures found in other standards, such as BAL-001’s ‘entity…shall.. operate such that…’ structure or BAL-001-TRE’s ‘entity….shall….meet (or exceed)’ structure may also work well for PRC-029.

ERCOT notes that FERC Order 901 states, “we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to use appropriate settings (i.e., inverter, plant controller, and protection) to ride through frequency and voltage system disturbances and that permit IBR tripping **only to protect the IBR equipment** in scenarios similar to when synchronous generation resources use tripping as protection from internal faults. The new or modified Reliability Standards must require registered IBRs to continue to inject current and perform frequency support during a Bulk-Power System disturbance” (emphasis added). To meet this directive, it may be important to clearly specify that partial failures (individual IBR unit trips or abnormal responses) also fall under PRC-029.

ERCOT therefore recommends modifying the Purpose statement for PRC-029 as follows: “To ensure that Inverter-Based Resources**, and their IBR Units,** remain connected and perform operationally as expected to support the Bulk-Power System during and after defined frequency and voltage excursions.”

The figures in Attachments 1, 2, and 3 appear to be intended to be graphical representations of the tables. To that extent, they are redundant (and potentially contradict what is in the tables). They may be valuable in visualizing the requirements, but they are also ambiguous in that the lines are not precisely defined, and it is not clear if ride-through is required on the lines themselves. ERCOT recommends that these figures be moved to the Technical Rationale or that Attachments 1, 2, and 3 include a clarification that the plots are for visualization purposes only and that the tables define what is actually enforceable

Item 7 in Attachment 1 should not imply that the IBR shall trip beyond the minimum duration. While the inclusion of the term "minimum" helps clarify item 7, the "shall not trip until…" language implies that the IBR shall trip once the minimum ride-through time duration has elapsed.

SDT’s proposed language:

“At any given voltage value, each IBR shall not trip until the time duration at that voltage exceeds the specified minimum ride-through time duration. If the voltage is continuously varying over time, it is necessary to add the duration within each band of Tables 1 and 2 over the 10-second time period to determine compliance.”

ERCOT’s proposed language:

"The IBR shall ride through voltage conditions beyond those specified in Tables 1 and 2 above to the maximum extent the equipment allows. If the voltage is continuously varying over time, it is necessary to add the duration within each band of Tables 1 and 2 over the 10-second time period to determine compliance."

Similar wording should also be applied in item 3 of Attachment 2 and item 4 of Attachment 3.

ERCOT is concerned that item 10 in Attachment 1 ("If the positive sequence voltage at the high-side of the main power transformer enters the Permissive Operation Region, an IBR may operate in current block mode if necessary to protect the equipment") is inconsistent with the following directive from paragraph 190 of FERC Order 901 (as cited in the technical rationale): "Any new or modified Reliability Standard must also require registered IBR generator owners and operators to prohibit momentary cessation in the no-trip zone during disturbances."

The proposed defined terms do not seem to be appropriate for the NERC glossary, especially if they are intended to be used exclusively for IBRs. If the SDT keeps these proposed terms, the definitions should be improved to include durations in addition to voltage ranges and to note that they are only valid for application to IBRs. Furthermore, there are inconstancies between these terms and Tables 1 and 2 in Attachment 1. For example, the Continuous Operating Region is defined as 0.9-1.1 pu (inclusive), but the tables specify only a one second ride-through time for 1.1pu voltage and an 1800 second ride-through time for voltages greater than or equal to 1.05pu, which is not consistent with the concept of continuous operations. Additionally, the terms are used inconsistently in PRC-029, as the terms are defined as "Operating Regions," but frequently appear in PRC-029 as "Operation Regions."

The Technical Rationale includes the following language:

"The proposed PRC-029 must be understood as an event-based standard. Compliance with PRC-029 is determined from IBR ride-through performance during transmission system events in the field and not from interconnection studies, transmission planning studies, operational planning studies, or from IBR models."

ERCOT recommends that the SDT add basic expectations to the Technical Rationale instead of simply stating that compliance is not determined by studies. For example, GOs should design and/or test their facilities to help ensure they won't be non-compliant during an actual event. Furthermore, it would be helpful to offer advice or SDT opinions on how ride-through should be evaluated during design, interconnection, planning, and operational studies. Even though deficient performance in such studies may not be a violation of PRC-029, it makes little sense to proceed with or allow an interconnection of a plant whose simulation models indicate that it will be unable to comply with PRC-029. Such guidance in the Technical Rationale would be beneficial for industry even if the Requirements in the standard do not contain a corresponding mandate.

The Technical Rationale should describe the basis for the "6-second frequency ride-through capability requirement for frequencies in the ranges of 61.8Hz to 64Hz or 57.0Hz to 56.0Hz range," as it is unclear why this approach was chosen instead of an approach that goes all the way up to 65 Hz and down to 55 Hz for 10 seconds or only up to 63.5 Hz and down to 56.5 Hz for 5 seconds.

It is also unclear how the SDT addressed the phase lock loop (PLL) loss of synchronism concerns discussed in FERC Order 901. While there is certainly an interrelationship, certain protection systems like PLL loss of synch may not need to be enabled. Even if enabled, these systems may, if not correctly configured, require additional tuning to ensure the PLL circuit properly controls and prevents some of the other parameters from tripping the unit offline (e.g. phase angle, RoCoF, and overvoltage). The SDT should consider adding additional language to PRC-029 to clarify that phase lock loss of synchronism trips (whether directly or indirectly involved) are not allowed.

The SDT should also consider adding the following items to Attachment 1 for clarity:

11. To the extent possible, IBRs should not use these curves as the absolute voltage or frequency protection set points but should strive to exceed them up to their equipment capabilities while still ensuring adequate equipment protection.

12. IBRs are not required to trip when voltage and frequency are in the may-trip or permissive operation regions.

Additionally, ERCOT has overall concerns with the work plan pushing the planner and operator requirement changes to the final phases. FERC Order 901 states, "To the extent NERC determines that a limited and documented exemption for those registered IBRs currently in operation and unable to meet voltage ride-through requirements is appropriate due to their inability to modify their coordinated protection and control settings, we direct NERC to develop new or modified Reliability Standards to mitigate the reliability impacts to the Bulk-Power System of such an exemption. As NERC will consider the reliability impacts to the Bulk-Power System caused by an such [sic] exemption, we believe that the concerns raised by NYSRC and Indicated Trade Associations on the appropriate registered entity responsible for implementing the mitigation activities, and the nature of such mitigation, should be addressed in the NERC standards development process."

Due to the interrelationship between these factors, the allowance for limited exemptions should be linked to the need to mitigate the impact of such exemptions, which will take time in and of itself. In addition, Order 901 directs NERC to consider the reliability impacts of such an exemption. If the SDT does not have identified quantities or models of likely exemptions to assess the impact of allowing exemptions, it is unclear how NERC is considering the reliability impacts of allowing exemptions. There must be guardrails in place to ensure that exemptions are truly limited, not open-ended, and there should be verification by means of accurate models and studies that the system can withstand the impacts of exemptions. If such studies demonstrate unreliable operations (i.e. Instability, Cascading Outages, and uncontrolled separation) would result from granting exemptions, then the exemptions should not be accepted. While ERCOT understands the impacts to generator owners, such assessment and determination should be made under FERC's direction to ensure that the limited exemptions and risk posed by such exemptions are balanced in such a way that the system maintains Reliable Operation.

Finally, regarding the implementation plan, ERCOT does not agree with how the FERC Order 901 excerpt quoted under "Equipment Limitations and Process for Requirement R6" has been applied. The FERC Order 901 excerpt refers to "typically older IBR technology," which would exclude a majority of IBRs that are in operation today. Aligning eligibility for PRC-029-1 exemptions based on documented equipment limitations under Requirement R6 with the effective date of PRC-029-1 would allow potentially hundreds of GWs of newer IBRs to qualify for exemptions. Such an allowance could result in a failure to realize the reliability benefits FERC intended to capture, as it would allow legacy IBRs to claim exemptions even if they are ultimately capable of complying with the requirements of PRC-029. Unless there is assurance, based on validated and accurate models, that planners and operators can verify that the System can withstand the impact of allowing these exemptions, this allowing this level of potential exemptions may not allow for Reliable Operations. In such instances where exemptions may not allow for Reliable Operations, there should be additional evaluation of available physical modifications (e.g. upgrade kits, new power plant controllers, new controller cards/circuits, control communication networks, component upgrades) for IBR technology that is not approaching its end of life and or an upcoming replacement/refurbishment cycle like "typically older IBR technology" is. Additionally, IBRs that make physical modifications to achieve compliance or that have to make software changes at multiple sites may need additional implementation time when such changes require changes at each individual inverter or turbine.

ERCOT expresses appreciation for all of the SDT's hard work in meeting an expedited timeline for developing a technically complex set of Requirements that attempts to balance elements from IEEE 2800, FERC Orders, NERC recommendations, and vast amounts of stakeholder input. The SDT is to be commended for its progress thus far on this critical standard.

Likes 0	
Dislikes 0	

Response	
Shonda McCain - Omaha Public Power District - 6	
Answer	
Document Name	
Comment	
OPPD supports comments provided by GRE: Michael Brytowski, Great River Energy, 3, 4/17/2024	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	
Document Name	
Comment	
For PRC-029-1 PG&E asks the SDT the following question: Does Table 1 or 2 apply to Type 4 Wind IBRs? It is unclear which table it would apply to and should be clarified since Table 1 specifies “Wind IBR” but not which types of Wind IBRs. PG&E suggests reconsidering the use of the term “trip” or “no-trip.” Per IEEE 2800-22, “trip” for IBRs may not mean the same as has been traditionally used for synchronous machines and other electric elements. For PRC-024-4 PG&E has the following question for the SDT to clarify: For Transmission Owners, does new language in sections 4.1.2 & 4.2.2 only apply to Synchronous Condensers?	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	

Document Name	
Comment	

NextEra aligns with EEI's comments:

PRC-029-1 (Applicability Section) Comments: EEI does not support the Applicability Section of PRC-029-1 for the following reasons:

{C}1. Applicability details should not be contained in footnotes. Please remove footnote 1 from the Applicability Section.

{C}2. Voltage Source Converter – High-voltage Direct Current (VSC-HVDC) are not defined or justified within the Technical Rationale as to why these resources need to be added PRC-029.

{C}3. Without a justification of a need to include VSC-HVDC systems, TOs should be removed from PRC-029-1.

{C}4. EEI does not support the use of the term "BPS IBRs" because no such term exists in the NERC Glossary of Terms that might provide entities with the knowledge to know definitively which IBRs are applicable.

{C}5. EEI also does not support language that points to the registration criteria.

To address our concerns, we suggest the following changes to the Applicability Section of PRC-029-1, noting the Facilities portion of our comments utilize the recommendations from the Project 2020-06 SDT (see boldface changes below):

{C}**4. Applicability:**

{C}4.1 Functional Entities:

{C}4.1.1 Generator Owner

{C}**4.1.2** {C}**Transmission Owner (and footnote 1)**

{C}4.2 Facilities: **(1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. For purposes of this standard, the term "applicable Inverter-Based Resource" or "applicable Inverter-Based Resources" refers to the following:**

{C}**4.2.1** {C}**BPS IBRs**

{C}**4.2.2** {C}**IBR Registration Criteria**

PRC-024 Comments: While there were no questions related to the proposed modifications to PRC-024-4, EEI does not support all of the proposed changes made to PRC-024-4. Note the following:

Applicability Section of PRC-024-4

EEI does not support changing the intent of 4.2.1.4 (Previously 4.2.1.5) to include multiple synchronous generators connecting to a common bus under the BES Definition, Inclusion I4. Since the development of the BES definition, Inclusion I4 did not include or intend to include synchronous generators. Had that been the intent, the SDT could have included synchronous generator resources in I4. Furthermore, the BES Reference Document states in Chapter I4: BES Inclusion the following:

Dispersed power producing resources are small-scale power generation technologies that use a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include, but are not limited to: solar, geothermal, energy storage, flywheels, wind, microturbines, and fuel cells.

While EEI is open to making modifications to the BES Definition, trying to provide interpretations within individual Applicability Sections of proposed NERC Reliability Guidelines is not the proper method to make such a change. For this reason, and since 4.2.1.4 (previously 4.2.1.5) was intended to address IBRs; this part of the Applicability Section of PRC-024-4 should be deleted.

Comments on the proposed New Definitions

EEI has no concerns with the proposed new definitions, but we do have some non-substantive comments on their usage throughout PRC-029, Implementation Plan and Technical Rationale. (See below)

{C}· Usage of the newly defined terms deviated from the defined term within PRC-029 and the Technical Rational. (i.e., Operating vs. Operations)

{C}· Incorrectly stating in the Implementation Plan that there were no newly defined terms. Please correct this error.

Continuous Operating Region – Only used once in Requirement 2.3.

{C}· Continuous Operation Region used in Requirements 2.1, 2.1.2, 2.4, & once in Attachment 1 (i.e., suggest changing the defined term to Continuous **Operation** Region or correct to Continuous **Operating** Region throughout)

{C}· Continuous Operation Region used twice in the Technical Rationale; Continuous Operating Region never used in the Technical Rationale.

Mandatory Operating Region – Never used in PRC-029

{C}· Mandatory Operation Region used in PRC-029 in Requirements 2.2, 2.3, 2.4 & once in Attachment 1 (i.e., suggest changing the defined term to Mandatory **Operation** Region or correct to Mandatory **Operating** Region throughout)

{C}· Mandatory Operation Region was used twice in Technical Rationale; Mandatory Operating Region was never used in the Technical Rational.

Permissive Operating Region – Never used in PRC-029

{C}· Permissive Operation Region used in PRC-029 in Requirements 2.3, 2.4, & used twice in Attachment 1 (i.e., suggest changing the defined term to Permissive **Operation** Region or correct to Permissive **Operating** Region throughout)

{C}· Permissive Operation Region used once in the Technical Rationale; Permissive Operating Region never used in the Technical Rationale.

Likes 0	
Dislikes 0	

Response	
Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	

Has the MPT Volts/Hz capability been considered when considering the high voltage/low frequency curves?

For R6, the use of "repair" seems inappropriate - an equipment limitation is not equivalent to a broken part in need of repair. We suggest that "repair(s) or replace the limiting element" in R6.1.4 and R6.2 be changed to "remedy the equipment limitation".

The standard requires IBR to ride-through regardless of operating condition of the transmission system. The IBR is typically designed to ride-through for planning events, most likely defined in TPL-001 standard. Considering 24 hour/365 day operation, the transmission system may be experiencing outages beyond planning events. During such an abnormal operating condition, the IBR may not be able ride-through system disturbances as specified. The same could also be true as the transmission system changes over time, as new transmission lines are added to the transmission system and generating plants are added to or removed from the transmission system. The IBR which is designed to ride-through certain transmission network and operating conditions at the time of entering commercial operation may not be able to do so if transmission network and operating conditions change significantly over time. The standard needs to recognize such issues and grant an exception if IBR fails to ride-through.

The SDT proposes to add continuous operating region, mandatory operating region, and permissive operating region terms to the Glossary of Terms. However, these terms are specific to voltage ride-through requirements. There is no reason to limit those terms to voltage ride-through capability only. The continuous and mandatory operation region terms could be applied to frequency ride-through capability as well. Refer to IEEE 2800 to see how these terms are used for both voltage and frequency ride-through capabilities.

Continuous/mandatory/permissive operating region terms:

1. The SDT uses continuous/mandatory/permissive “operating” region as well as continuous/mandatory/permissive “operation” region. Be consistent with either “operating” or “operation” throughout the standard.
2. Following comments to align voltage ranges in Attachment 1, Tables 1 & 2:
    - Mandatory Operating Region term should read like following: The range of voltages, measured at the high-side of main power transformer, that are ≥ 0.1 per unit and < 0.9 per unit OR > 1.1 per unit and ≤ 1.2 per unit.
    - Permissive Operating Region term should read like the following: The range of voltages, measured at the high-side of main power transformer, that is ≤< 0.1 per unit.

3. These terms specify voltage threshold, but which voltage is used in these terms is in the Attachment 1. Per attachment 1, the continuous and mandatory operating regions are based on phase-to-ground or phase-to-phase voltages. But the permissive operating region is based on positive-sequence voltage. The defined terms should also make it clear which voltage thresholds are defined.

Consider revising the purpose statement as following: To ensure that Inverter-Based Resources (IBRs) remain connected and support the Bulk Power System (BPS) during and after frequency and voltage excursions events.

Transmission Owner is included as a Functional Entity in section 4. However, footnote 1 makes it confusing. Would standard only apply to Transmission Owner when it owns the VSC-HVDC transmission facility connecting isolated IBR with BPS?

Currently, PRC-029-1 allows for a GO or TO to seek an exemption from meeting voltage-ride through requirements in R1 and R2.

Southern Company believes that GOs and TOs should be able to seek exemptions from meeting frequency and voltage ride-through requirements in R1 – R5.

The proposed standard only provides for VRT exemptions. Any consideration for FRT, ROCOF, phase angle?

Comment to PRC-024-4:

Facilities section 4.2.1.1 should include I2 of the BES definition and section 4.2.1.4 be removed or reference I2 in place of I4. I4 of the BES definition was intended to point to IBRs at the time of the latest BES definition adoption in 2018 as dispersed power resources and was not intended to point to synchronous generation resources.

Opportunity to clarify that legacy IBRs must maximize capabilities:

1. For NOGRR245, it has been advocated that legacy IBRs should make software / settings changes to maximize capabilities to meet or approach the new ride-through requirements, unless such changes are unreasonably priced.
2. Southern's experience is that software / settings changes are commercially reasonable. The "unreasonably priced" language is intended to protect against price gauging from OEMs.
3. The current PRC-029-1 draft requires legacy IBRs to meet the new voltage ride-through requirements unless a documented technical limitation exists. So a legacy IBR can document an exemption and have performance capabilities less than new VRT standard. But what happens if that legacy IBR owner later learns there is an available software / setting change that would reduce or remove the limitation? The current draft need clarity to address this.
4. Southern Company supports such a software / setting deployment requirement and believes it would (1) be commercially reasonable and (2) more clearly require ride-through capability maximization.

Finally, Southern Company supports EEI and NAGF comments.

Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	

While inclusive, is PRC-024-4 Facility Section Part 4.2.1.4 applicable to synchronous generators? Inclusion 4, when written, was designed to catch the wind/solar aspects of the generation fleet. Inclusion 2 seems to be more appropriate (if not already covered in 4.2.1.1). The MPT footnote appears to be limited to Quebec TO synchronous generators and does not include a reference to synchronous condensers (4.2.2

synchronous condenser applicable facilities simply says “step-up transformer(s)”). In PRC-024-4 Requirement 2 there is a reference to “MPT” and the introduction of Transmission Owner within Requirement. It is not clear if applicable to TOs outside of Quebec based on the language provided (from Requirement R2---“…a voltage excursion at the high-side of the GSU or MPT…” which the GSU/MPT is not mentioned in applicable Facilities for synchronous condensers Section 4.2.2). In Attachment 1 there is a similar issue in that footnote 8 on page 21 mentions the high-side of the GSU or MPT—Also should be noted that Footnote 8 does not appear to have an anchor (location within document to reference the footnote). On page 22 of Attachment 2A there are references to the GSU/MPT as well. Just seeking clarification to avoid an entity having a synchronous condenser indicating no applicability because of the language. This inconsistency in language does not appear to follow items 8 (“Clear Language”) and 10 (“Consistent Terminology”) of the Ten Benchmarks of an Excellent Reliability Standard as referenced in the Guideline for Quality Review of NERC Reliability Standards Project Documents.

PRC-029-1- SDTs need to use the same IBR terms and not add additional descriptors. Even the title of the Standard is not consistent. Should use the proposed definitions in 2020-06 Verifications of Models and Data for Generators for clarity and consistency. There is no such Facility as “IBR Registration Criteria”. Footnote 1 contains undefined terms which should be defined within this Standard if used. Because of the inconsistency in definition use, it is not clear whether this applies to the IBR or IBR Unit locations (even when stated that it does not apply to “individual inverter units or measurements takes at individual inverter unit terminals.” If looking at Project 2020-06, the inverters in a “common IBR Unit configuration’ as shown in Figure 2.2 and 2.3 of the Technical Rational are exactly at the individual IBR Units (see link [2020-06_IBR_Definitions_Technical_Rationale_02222024.pdf (nerc.com)](2020-06_IBR_Definitions_Technical_Rationale_02222024.pdf)). Is “exchange current” considered the same as “inject current” which is used (various ways) in other Standards being proposed? The new terms introduced address range of voltages that may not correlate to the Tables effectively. The Continuous Operating Region definition shows to **include** 1.1 per unit and should reflect the 1800 seconds in Table 1 and Table 2 but the 1.1 voltage per unit in the Tables show only a 1 second capability (Mathemataical expression includes 1.1 per unit in the Table which it should not). Furthermore the 1.2 voltage per unit is shown to be included in the Mandatory Operating Region but NOT in the Tables. Please clarify the expectations as entities had an issue in PRC-024 setting protection on the curves when initially mandatory. With conflicting information, and Figures that are not as explicit or appear to match the Tables, WECC is concerned there may be confusion. This language does not appear to follow Item 8 (“Clear Language”) and 10 of the Ten Benchmarks of an Excellent Reliability Standard as referenced in the Guideline for Quality Review of NERC Reliability Standards Project Documents.

At a minimum, bullet 2 under Attachment 1 Table 2 should mention all the types of IBR as listed in other Standards (Type 3 and type 4 of wind is covered in bullet 1, “Isolated IBR” is undefined, and 2.b. simply says “Other IBR plants” and limits hybrid to PV and “ESS” (possible typo that should be “BESS”?). The “not limited to” should remain and the SDT may say all are covered with said language but clarity could be provided by adding consistent language as used in other Standards. This inconsistency in language does not appear to follow items 10 (“Consistent Terminology”) of the Ten Benchmarks of an Excellent Reliability Standard as referenced in the Guideline for Quality Review of NERC Reliability Standards Project Documents.

Attachment 1 Table 2 Bullet 3 leaves the applicability to the TP but the TP is not called out as an applicable entity and this is an Operations Assessment time horizon. In the Technical Rationale it clearly states “*Compliance with PRC-029 is determined from IBR ride-through performance during transmission system events in the field and not from* ***interconnection studies, transmission planning studies****, operational planning studies, or from IBR models*.” So, if IBRs in a hybrid plant have issues, the TP is to blame for calling out the incorrect Table? TPs may very well have the studies to determine how long a ride-through should be sustained by IBRs, but there is no compliance responsibility (not saying there should be—should be responsibility properly assigned through the Standards process). Bullet 4 allows the PC or TP to change the Requirement criteria but there is no accountability if done (furthermore no notifications for awareness to those entities in the Operations side of business). The apparent responsibility does not appear to follow items 1 (“Applicability”) of the Ten Benchmarks of an Excellent Reliability Standard as referenced in the Guideline for Quality Review of NERC Reliability Standards Project Documents.

"MPT" is not defined in the Standard yet used repeatedly. Clarity can be provided with a footnote or addition of a definition (not that synchronous condenser use in PRC-024-4 was unclear for MPT).

There are only Severe VSLs for Requirements R1 through R5. Clarity on where the inverter is (based on the 2020-06 drawings provided and language in this Standards Technical Rational) will be important to understand. Failure of individual IBR units (as defined in 2020-06) appears to not be addressed9unless it is intended to be addressed by the Sever VSL) and will have an impact on being complaint at the IBR level.

Likes 0	
Dislikes 0	

Response

Romel Aquino - Edison International - Southern California Edison Company - 3

Answer	
Document Name	

Comment

See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	
Document Name	

Comment

See EEI Comments

Likes 0	
Dislikes 0	

Response

Carey Salisbury - Santee Cooper - 1,3,5,6, Group Name Santee Cooper

Answer	
Document Name	

Comment

For each of the measures M1-M5, what “other evidence” can demonstrate compliance with R1-R5 other than recorded data? How does the drafting team believe that generator owners can assure this performance expectation can be achieved prior to an actual event? There is no test verification that can be performed to confirm the expected performance that considers every type of system disturbance that can occur.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Many references in the requirements point toward Continuous Operating Region, Mandatory Operating Region, and Permissive Operating Region "as specified in **Attachment 1**", yet Attachment 1 does not specify any of these regions. Operating Regions should be added to Attachment 1 tables and figures.

No-trip zone Figures 1 & 2 don't match the tables.

Is there a point or distinction being made by using capitalized "Systen" instead of undefined "system" in requirements?

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

The Implementation Plan should be extended to 36 months to allow for monitoring equipment to be installed at sites completed before PRC-029 becomes enforceable, to demonstrate performance and compliance with the standard.

Likes 0	
Dislikes 0	

Response

Dave Krueger - SERC Reliability Corporation - 10	
Answer	
Document Name	
Comment	
On behalf of the SERC Generator Working Group: Consider allowing for some period of time beyond the effective date of PRC-029 to document limitations per (R6) – contemplate the real impact to BES reliability of limitation documentation. Consider synchronizing the phase in of PRC-028 with the measures such as M1 stating "*shall have evidence of actual recorded data*...". For each of the measures M1-M5, what "other evidence" can demonstrate compliance with R1-R5 other than recorded data? How does the drafting team believe that generator owners can assure this performance expectation can be achieved prior to an actual event? There is no test verification that can be performed to confirm the expected performance that considers every type of system disturbance that can occur.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG supports IESO, HQ, and NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	

MP agrees with the NSRF's suggestions to enhance PRC-029, especially regarding limiting the power of equipment limitations from exempting applicable entities from compliance, expanding the applicable facilities to include IBRs of 20MVA and above, and more precisely defining applicable entities and facilities within the text of the standard.

MP also suggests that a formal definition of "Inverter-Based Resources" precede the adoption of the standard.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5

Answer	
Document Name	

Comment

We are concerned that the standard refers to a defined term for IBR which has yet to be adopted in project 2020-06.

We suggest that the drafting team ensure consistent language is used in the section 4.2 "Facilities" section with the other projects such as 2021-04 (PRC-028) and 2023-02(PRC-030). Section 4.2.2 refers to IBR Registration criteria, however it is our understanding that section 4.2.1 would refer to GOs and TOs "that own equipment as identified in section 4.2" and where section 4.2 would indicate "the Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV." .

We question why "attachment 1" and "Requirement R6" are written in bold.

Attachment 1: should the "including, but not limited to" in table 2 include the same list (or minimally the same wording) that is found in the technical rationale of the IBR definition in project 2020-0?. For example, the IBR list in 2020-06 refers to "solar photovoltaic" whereas table 2 refers to "photovoltaic (PV)".

In what standard does the PC/TP define the applicable table in point 3 of section 2 in attachment 1? Same question for the voltage base for per unit calculation in both Attachment 1 and 2. Is there a corresponding requirement in another standard that requires the PC/TP to do this?

· Terms : Mandatory and permissive operation should be defined based on the attachment figures allowing for interconnections to use different requirements

· A-4.2.2 What is the IBR registration criteria? Add a clear reference and make sur the user understands what the IBR registration criteria is.

· B-R2-2.1 Attachment 1 only uses "no-trip zone". Define continuous operating region more clearly in the table (similar to what is done in PRC-024-4)

· B-R2-2.1.2 Can the TP ask for a mix of active/reactive power based on a predetermined ratio (currently only indicated as active or reactive).

· B-R2-2.2 Attachment 1 only uses "no-trip zone". Define "mandatory operation region" in Attachment 1.

· B-R2-2.4 Permissive operation region is not used or defined in attachment 1.

· B-R3. The document refers to an overvoltage value of 1.2pu. It should refer to a voltage exceeding the mandatory operating region in order for Interconnections to set their own overvoltage table.

· B-R3. Since R6 does not apply to this requirement, what will be done with existing IBR that cannot ride through these overvoltages ? An exemption clause is required for existing IBR that cannot be modified or upgraded.

· B-R4. The 5Hz/s value should be moved to Attachment 3 and B-R4 should only refer to the value in the Attachment.

· B-R4. Since R6 does not apply to this requirement, what will be done with existing IBR that cannot ride through these frequencies and ROCOF ? (for instance, for all the HQ connected projects, the ROCOF requirement was 4Hz/s) An exemption clause is required for existing IBR that cannot be modified or upgraded.

· B-R5. Since R6 does not apply to this requirement, what will be done with existing IBR that cannot ride through this phase angle jump ? An exemption clause is required for existing IBR that cannot be modified or upgraded.

· Attachment 1. Tables 1 and 2: Indicate what is considered as “continuous operation”, “mandatory operation” and “permissive operation” in an additional column.

· Attachment 1. HQ needs a Quebec regional variance since the Québec Interconnection has its own requirements in this regard.

· Attachment 2. Bullet 3: This sentence is hard to read. Proposed replacement: "Each IBR shall not trip unless the cumulative time of one or more instances in which the instantaneous voltage exceeds the respective voltage threshold over a 1-minute time window exceeds the minimum ride-through time"

· Attachment 2. HQ needs a Quebec regional variance since the Québec Interconnection has its own requirements in this regard.

· Attachment 3. This attachment should also include the maximum absolute ROCOF value.

· Attachment 3. HQ needs a Quebec regional variance (or the equivalent through the “regie de l’energie” approval process).

· B-R2-2.1.2 Which entity between Transmission Planner, Planning Coordinator, Reliability Coordinator and Transmission Operator has priority to specify those requirements?

· B-R2-2.4 Which entity between Transmission Planner, Planning Coordinator, Reliability Coordinator and Transmission Operator has priority to specify those requirements?

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	

The implementation plan is also very aggressive and for some generators may be impossible to meet.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Maozhong Gong - GE - GE Wind - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

Overall comments:

1. Implementation date: 6 months is not sufficient for IBR manufacturers to meet the new standard. Instead we propose 2yrs to accommodate product development/adequacy and appropriate validation.

2. For R6, R3,R4,R5 should be included as well for the documented limitation communication (see R6 comments below).

3. For Attachment 1, for VSC-HVDC connected IBRs, it is not clear if Table 2 is applicable at the MPT on grid side or on the IBR side of HVDC (see Attachment 1 comments below)

4. For MFRT, GEV suggests to align to IEEE2800-2022 7.2.2.4 for consistency (see Attachment 1 comments below).

GEV comments to R6: The language in R6 only allows documented limitations for Requirements R1 and R2. The standard must allow for documentation of limitations for Requirements R3, R4, and R5, as some existing site equipment was not designed to these requirements originally.

GEV comments to Table 2 in Attachment 1: For VSC-HVDC connected IBRs, please clarify if Table 2 is applicable at the MPT on grid side or on the IBR side.

GEV comments to MFRT: For MFRT requirements, GE Vernova strongly suggests that this language should align to IEEE2800-2022 7.2.2.4. Exceptions from the IEEE standard that are relevant were not included, making these requirements inconsistent with 2800-2022.

Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	
Document Name	
Comment	
PRC-24-4 mentined BPS in the Purpose section. We believe it is typo becuase the rest of the standard the applicabilty is for BES elements. The implemetation plan to to strict to allow cost effect implementation.	
Likes 0	
Dislikes 0	
Response	
Imane Mrini - Austin Energy - 6, Group Name Austin Energy	
Answer	
Document Name	
Comment	
AE supports comments provided by Texas RE and the NAGF	

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI offers the following additional comments on both PRC-024 & PRC-029:

PRC-029-1 (Applicability Section) Comments: EEI does not support the Applicability Section of PRC-029-1 for the following reasons:

1. Applicability details should not be contained in footnotes. Please remove footnote 1 from the Applicability Section.
2. Voltage Source Converter – High-voltage Direct Current (VSC-HVDC) are not defined or justified within the Technical Rationale as to why these resources need to be added PRC-029.
3. Without a justification of a need to include VSC-HVDC systems, TOs should be removed from PRC-029-1.
4. EEI does not support the use of the term "BPS IBRs" because no such term exists in the NERC Glossary of Terms that might provide entities with the knowledge to know definitively which IBRs are applicable.
5. EEI also does not support language that points to the registration criteria.

To address our concerns, we suggest the following changes to the Applicability Section of PRC-029-1, noting the Facilities portion of our comments utilize the recommendations from the Project 2020-06 SDT (see removals (i.e., TOs, registration criteria, etc. and other text) and boldface changes below:

4. Applicability:

4.1 Functional Entities:

4.1.1 Generator Owner

Facilities:

(1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

PRC-024 Comments: While there were no questions related to the proposed modifications to PRC-024-4, EEI does not support all of the proposed changes made to PRC-024-4. Note the following:

Applicability Section of PRC-024-4

EEI does not support changing the intent of 4.2.1.4 (Previously 4.2.1.5) to include multiple synchronous generators connecting to a common bus under the BES Definition, Inclusion I4. Since the development of the BES definition, Inclusion I4 did not include or intend to include synchronous generators. Had that been the intent, the SDT could have included synchronous generator resources in I4. Furthermore, the BES Reference Document states in Chapter I4: BES Inclusion the following:

Dispersed power producing resources are small-scale power generation technologies that use a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include, but are not limited to: solar, geothermal, energy storage, flywheels, wind, microturbines, and fuel cells.

While EEI is open to making modifications to the BES Definition, trying to provide interpretations within individual Applicability Sections of proposed NERC Reliability Guidelines is not the proper method to make such a change. For this reason, and since 4.2.1.4 (previously 4.2.1.5) was intended to address IBRs; this part of the Applicability Section of PRC-024-4 should be deleted.

Comments on the proposed New Definitions

EEI has no concerns with the proposed new definitions, but we do have some non-substantive comments on their usage throughout PRC-029, Implementation Plan and Technical Rationale. (See below)

- Usage of the newly defined terms deviated from the defined term within PRC-029 and the Technical Rational. (i.e., Operating vs. Operations)
- Incorrectly stating in the Implementation Plan that there were no newly defined terms. Please correct this error.

Continuous Operating Region – Only used once in Requirement 2.3.

- Continuous Operation Region used in Requirements 2.1, 2.1.2, 2.4, & once in Attachment 1 (i.e., suggest changing the defined term to Continuous **Operation** Region or correct to Continuous **Operating** Region throughout)
- Continuous Operation Region used twice in the Technical Rationale; Continuous Operating Region never used in the Technical Rationale.

Mandatory Operating Region – Never used in PRC-029

- Mandatory Operation Region used in PRC-029 in Requirements 2.2, 2.3, 2.4 & once in Attachment 1 (i.e., suggest changing the defined term to Mandatory **Operation** Region or correct to Mandatory **Operating** Region throughout)
- Mandatory Operation Region was used twice in Technical Rationale; Mandatory Operating Region was never used in the Technical Rational.

Permissive Operating Region – Never used in PRC-029

- Permissive Operation Region used in PRC-029 in Requirements 2.3, 2.4, & used twice in Attachment 1 (i.e., suggest changing the defined term to Permissive **Operation** Region or correct to Permissive **Operating** Region throughout)

- Permissive Operation Region used once in the Technical Rationale; Permissive Operating Region never used in the Technical Rationale.

Likes 0	
Dislikes 0	

Response

Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3

Answer	
Document Name	

Comment

1. Implementation should align with PRC-028-1 proposed implementation to ensure data collecting information is available to adhere to PRC-029-1.

2. PRC-024-4 Applicability and Purpose should include asynchronous type 1 and type 2 wind since these are not IBRs and therefore not applicable to PRC-029:

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

4.2.1.6 Type I and type II asynchronous wind generation identified in the BES Definition, Inclusion I4.

3. Suggest that the drafting team ensure consistent language is used in the section 4.2 "Facilities" section with the other projects such as Project 2021-04 (PRC-028) and 2023-02(PRC-030). We suggested the following language be included in the applicability section. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Please consider using the risk-based approach when drafting standards.

Likes 0	
Dislikes 0	

Response

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

Duke Energy recommends the implementation of EEI and NAGF comments.

For clarification, expand the following subparts as stated below:

4.1. Functional Entities:

4.1.1. Transmission Owner that owns equipment as identified in section 4.2.

4.1.2. Generator Owner that owns equipment as identified in section 4.2.

4.2. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	

The applicability section should match applicability sections of other IBR standards under development, PRC-030 and PRC-028.

Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	

Comment
The NAGF provides the following additional comments for consideration: *PRC-024:* *a. Section 4.2.1.2 – Consider adding the language "Main Power Transformer (MPT)".* *b. Section 4.2.1.4 and 4.2.1.5 - Recommend that the proposed language be modified to reference BES Definition – Inclusion I2 instead of Inclusion I4 – Dispersed Power Producing Resources. The proposed new PRC-029 standard's focus is on Frequency and Voltage Ride-through Requirements for Inverter-Based Generating Resources and therefore should include a reference BES I4 resources.* *PRC-029:* *a. Terms – the NAGF requests additional clarification on how the proposed defined terms work with the proposed PRC-030. Will analysis be required for an event under the proposed PRC-029 and under PRC-030? Potential double jeopardy issue. Alternatively, if tripping is allowed under PRC-029, would an analysis still be required under PR-030?* *b. Section 4.2 - Facilities:* *i. Use of the capitalized term "Bulk Power System (BPS) Inverter-Based Resources (IBR)" should be reviewed as it is not a defined term in the NERC Glossary of Terms. In addition, it is very likely that not all Bulk Power System Inverter-Based Resources will be registered even under NERC's modified Rules of Procedure. Until the definition of Inverter-Based Resources is approved, the SDT should only use the term "inverter-based resource" if needed.* *ii. The NAGF requests clarification if IBR plants that include synchronous condensers should meet the PRC-029 requirements.* *c. Comments Related to Attachments:* *i. Attachment 1 – Recommend adding to the table a column that species what area is the Continuous Operating Region, Mandatory Operating Region and Permissive Operating Region. As currently structured, it is not clear where the different regions begin or end. If possible, the NAGF recommends a graph showing the different areas for clarity.* *ii. The abbreviations "MPT" and "ESS" are not defined within the standard/attachment. Please ensure all acronyms/initializations are fully defined for use.* *iii. If the term ESS is intended to mean Energy Storage Systems, does this also apply to water storage systems, or only Battery Energy Storage Systems? If the intent is to refer to Battery Energy Storage Systems, please modify the term used.* *iv. Attachment 1, note 3 – There does not appear to be a requirement proposed for the Transmission Planner (TP) to provide direction as stated in note 3. Request clarification on how the TP will provide such guidance/direction on the applicable table to be used.* *v. Attachment 1, Note 7 – These notes appear to state that no unit should trip in a 10 second period if voltage is fluctuating, but the summation of time interval does not appear to be 10 seconds in most instances. As an example, assuming that the SDT intends for a generator to follow the voltage for 10 seconds when it is fluctuating between .7 and .5, the unit should be allowed to trip when voltage is below the .5 level*

for 1.2 seconds. However, note 7 appears to state that there is a 10 second limit if voltage were to be below .7 for 1 second, then goes below .5 for 3 seconds, then returns to the .7 for 6 seconds. Please verify this interpretation is correct, or how this language should be understood.

vi. Attachment 1, Notes 7 and 8 – Both of these items discuss cumulative numbers in Tables 1 and 2. As worded, it is unclear if the intent is to add the numbers in Table 1 to the numbers in Table 2, or if the intent is to add the numbers in the second column of Table 1 for those resources that are considered Table 1 entities, and similar for Table 2 entities. Please clarify the wording so the intent of the standard is clear.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

AZPS supports the following comments that were submitted by EEI on behalf of its members:

PRC-029-1 (Applicability Section) Comments: EEI does not support the Applicability Section of PRC-029-1 for the following reasons:

1. Applicability details should not be contained in footnotes. Please remove footnote 1 from the Applicability Section.

2. Voltage Source Converter – High-voltage Direct Current (VSC-HVDC) are not defined or justified within the Technical Rationale as to why these resources need to be added PRC-029.

3. Without a justification of a need to include VSC-HVDC systems, TOs should be removed from PRC-029-1.

4. EEI does not support the use of the term "BPS IBRs" because no such term exists in the NERC Glossary of Terms that might provide entities with the knowledge to know definitively which IBRs are applicable.

5. EEI also does not support language that points to the registration criteria.

To address our concerns, we suggest the following language in the Applicability Section of PRC-029-1, noting the Facilities portion of our comments utilize the recommendations from the Project 2020-06 SDT):

4. Applicability:

4.1 Functional Entities:

4.1.1 Generator Owner

4.2 Facilities: (1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

PRC-024 Comments: While there were no questions related to the proposed modifications to PRC-024-4, EEI does not support all of the proposed changes made to PRC-024-4. Note the following:

Applicability Section of PRC-024-4

EEI does not support changing the intent of 4.2.1.4 (Previously 4.2.1.5) to include multiple synchronous generators connecting to a common bus under the BES Definition, Inclusion I4. Since the development of the BES definition, Inclusion I4 did not include or intend to include synchronous generators. Had that been the intent, the SDT could have included synchronous generator resources in I4. Furthermore, the BES Reference Document states in Chapter I4: BES Inclusion the following:

Dispersed power producing resources are small-scale power generation technologies that use a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include, but are not limited to: solar, geothermal, energy storage, flywheels, wind, microturbines, and fuel cells.

While EEI is open to making modifications to the BES Definition, trying to provide interpretations within individual Applicability Sections of proposed NERC Reliability Guidelines is not the proper method to make such a change. For this reason, and since 4.2.1.4 (previously 4.2.1.5) was intended to address IBRs; this part of the Applicability Section of PRC-024-4 should be deleted.

Comments on the proposed New Definitions

EEI has no concerns with the proposed new definitions, but we do have some non-substantive comments on their usage throughout PRC-029, Implementation Plan and Technical Rationale. (See below)

- Usage of the newly defined terms deviated from the defined term within PRC-029 and the Technical Rational. (i.e., Operating vs. Operations)
- Incorrectly stating in the Implementation Plan that there were no newly defined terms. Please correct this error.

Continuous Operating Region – Only used once in Requirement 2.3.

- Continuous Operation Region used in Requirements 2.1, 2.1.2, 2.4, & once in Attachment 1 (i.e., suggest changing the defined term to Continuous Operation Region or correct to Continuous Operating Region throughout)
- Continuous Operation Region used twice in the Technical Rationale; Continuous Operating Region never used in the Technical Rationale.

Mandatory Operating Region – Never used in PRC-029

- Mandatory Operation Region used in PRC-029 in Requirements 2.2, 2.3, 2.4 & once in Attachment 1 (i.e., suggest changing the defined term to Mandatory Operation Region or correct to Mandatory Operating Region throughout)
- Mandatory Operation Region was used twice in Technical Rationale; Mandatory Operating Region was never used in the Technical Rational.

Permissive Operating Region – Never used in PRC-029

- Permissive Operation Region used in PRC-029 in Requirements 2.3, 2.4, & used twice in Attachment 1 (i.e., suggest changing the defined term to Permissive Operation Region or correct to Permissive Operating Region throughout)
- Permissive Operation Region used once in the Technical Rationale; Permissive Operating Region never used in the Technical Rationale.

Likes 0	
Dislikes 0	

Response

Joy Brake - Nova Scotia Power Inc. - NA - Not Applicable - NPCC

Answer	
Document Name	

Comment

If using ALL CAPS, consider RCF as the acronym. It is not that significant a metric to require capitalization of "of".

RoCoF is also used in many other jurisdictions.

FERC order:

"In other words, under certain conditions some IBRs cease to provide power to the Bulk-Power System due to how they are configured and programmed. " Yes, but PRC-024 now prohibits this. In some cases, settings in the older plants can be tweaked to improve performance but we are having trouble getting good models from the GOs. To address NERC concerns we need requirements for better models.

"some models and simulations incorrectly predict that some IBRs will ride through disturbances, i.e., maintain real power output at pre-disturbance levels and provide voltage and frequency support consistent with Reliability Standard PRC-024-3". Only if incorrectly modelled. Require better modelling to identify issues and determine mitigations. PRC-029 will not stop the problem of simulating a system that works great in the virtual world but will not perform when called upon.

Likes 0	
Dislikes 0	

Response

Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC

Answer	
Document Name	

Comment

PNM agrees with EEI's comments.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE has the following additional comments for PRC-029-1:

1. Texas RE recommends the new terms included in PRC-029-1 clearly state the voltage measurements included are at the high-side of the main transformer connecting to the BPS transmission system. Texas RE suggests the following changes (in bold):

Term(s): Continuous Operating Region – The range of voltages, measured at the high-side of the **BPS** main power transformer, that are ≥ 0.9 per unit and ≤ 1.1 per unit.

Mandatory Operating Region – The range of voltages, measured at the high-side of the **BPS** main power transformer, that are > 0.1 per unit and < 0.9 per unit – or – > 1.1 and ≤ 1.2 per unit.

Permissive Operating Region – The range of voltages, measured at the high-side of the **BPS** main power transformer, that is ≤ 0.1 per unit.

2. Consider changing ‘each IBR’ to ‘each IBR Facility’ for all the requirements.

3. For consistency, consider modifying the title of the standard to (in bold):

Title: Frequency and Voltage Ride-through Requirements for Inverter-Based **Generating** Resources

4. Consider changing 4.2.1 to **BES** IBRs (instead of BPS IBRs) to be consistent with other PRC standards such as proposed reliability standards PRC-028-1 and PRC-024-4.

5. Consider changing voltage (per unit) in Attachment 1 (third row) to greater than 1.05 pu only (i.e. remove the equal 1.05 criterion). Typical BES and BPS systems are expected to operate continuously for voltage levels 0.95 – 1.05 pu.

Attachment 1 - changes In Table 1 & Table 2 change > 1.05 to >1.05 **Add the following to Table 1 and 2:** **Voltage (per unit): > 0.9 Minimum Ride-Through: Continuous** **Voltage (per unit): < 1.05 Minimum Ride-Through: Continuous**	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	
Document Name	
Comment	
• GTC recommends increasing the implementation timeline to be 12 to 18 months after the effective date of the applicable governmental authority's order approving for both the PRC-024-4 and PRC-029-1 standards. • There were no balloting questions provided for the language changes in the PRC-024-4 standard. GTC recommends providing balloting questions for the industry to respond to the changes in the PRC-024-4 standard.	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	
Document Name	
Comment	
NERC should remain consistent with their revised Rules of Procedure by avoiding the use of "BPS IBR" terminology in the applicable facilities. This is overly broad and can lead to misinterpretation for Generator Owners who own IBRs that do and do not fit the 60 kV and 20 MVA thresholds. The third question in the Project 2020-06 comment form, copied below, is a clearer definition of IBR which NERC has determined has a material impact to the BPS. NERC should consider adopting this terminology in PRC-029	

Section 4. Applicability:

4.1 Functional Entities: Generator Owner, Generator Operator

4.2 Facilities: (1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and North American Generator Forum (NAGF) on question 4

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	
Document Name	

Comment

Dominion Energy supports EEI comments. In addition, we have the following coments:

The term BPS IBRs and IBR Registration Criteria are not clear-cut Facilities. The standard should reference terms available for use in the NERC Glossary of Terms to determine applicability, such as the BES defintion. As stated in the EEI comments, the BES defintion would be the appropriate place to address defintions of this type.

The Effective Date of 6 months following approval by FERC is too short for Generator Owners and Transmission Owners that own numerous IBR generating sites, to develop internal controls and processes; and perform the necessary compliance evaluations and possible settings changes to meet the ride-through criteria. Conversely, 6 months after the effective date is too long for documenting Limitations per Requirement R6.

The documentation of limitations is typically done during the compliance analysis and study. A staggered implementation plan, that takes into account the registration and requirements for Level 2 GO registrations should be designed and implemented.

The Implementation Plan should also consider those IBRs that are approved to be built and have had their Interconnection Studies approved. The contracts for building these sites are signed years in advance with the inverters ordered. A staggered applicability for R6 should be considered that allow for projects in service prior to 2027 or 2028 to be eligible for equipment limitations and those in service after to meet the performance criteria without limitations.

Likes 0	
Dislikes 0	

Response

George E Brown - Pattern Operators LP - 5

Answer	
Document Name	

Comment

Pattern Energy supports GRE's comments for this question.

Likes 0	
Dislikes 0	

Response

Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies

Answer	
Document Name	

Comment

The SDT explains in the draft PRC-029-1 Technical Rationale that "An IBR becomes noncompliant with PRC-029 only when an event in the field occurs that shows that one or more requirements were not satisfied." This, coupled with the removal of IBRs from PRC-024 applicability, would result in a lack of accountability until actual harm (i.e., failure to adequately support the reliability of the BES during a system event) occurs for IBRs not prepared to meet the performance requirements. There would not be auditable and enforceable requirements for owners of IBRs to proactively take action to reasonably ensure the performance requirements will be met. Reliability standards exist to prevent potential harm, which minimizes actual harm.

While RF acknowledges the observed limitations of the existing PRC-024 standard in preventing the undesirable responses of IBRs to the system disturbance events cited in the SAR, RF does not support the whole-sale elimination of frequency and voltage protection settings verification requirements for IBRs. Generator frequency protection settings verification is critical in ensuring UFLS programs are adequately coordinated with generator capabilities, and RF does not wish to rely on self-revealing events to determine where miscoordination exists between IBR frequency protection and UFLS. Unless additional verification requirements are added to PRC-029, RF believes PRC-024 should remain applicable to IBRs.

RF notes that the range of system conditions in which PRC-029 would require IBRs to remain online appear to be significantly larger than those established in PRC-024 (which would remain applicable to synchronous generators). Although the unique capabilities of IBRs may support such a large expansion for only IBR resource types, additional discussion of the technical justification for this expansion would be useful.

Regarding implementation, RF finds a 12-month implementation period acceptable.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment

The implementation plan is also very aggressive and for some generators may be impossible to meet.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	
Document Name	

Comment

- The new performance-based approach opens us up to a lot of issues with other tripping/cessation besides basic overvoltage/under voltage/frequency that our operations team has seen during events.
    - This protection is not modeled in basic models right now and will require substantial effort to ensure we can perform as required. AES CE requests that the Implementation Plan be modified to use a phased-in approach for existing sites to allow adequate time to prepare for these performance requirements.

Additionally, the standard and rationale is absent of language on studies/assessments that should be performed. AESCE believes that providing examples of the types of studies and assessments that should be run to ensure that resources would perform as expected is necessary for reliability and adequate implementation of this standard by GOs.

- Please provide additional clarification on acceptable limitations under R6. Language such as "hardware replacements or other costly upgrades" from the Technical rationale document is vague and open to interpretation.
- AESCE would like the SDT to consider the challenges with ensuring plants, particularly legacy operational plants, can ride through per the requirements. To ensure this or identify equipment limitations, studies and equipment information is necessary and is not available for most legacy equipment.
- First, EMT studies and RMS model studies are necessary to study plant ride-through capabilities specified in the standard. However, there are significant challenges with these models today that should be considered in the implementation and equipment limitations. Quality EMT models including all equipment information needed are not available for legacy equipment (inverters, PPCs). Many legacy inverters do not have an EMT model, and those that do have models that are not adequately validated against equipment performance. Creation of models is either not supported or can be developed at a very high cost. Models created after the inverters were initially released are of inadequate quality because the equipment is no longer able to be in a lab environment.
    - To consider this, AESCE suggests that the SDT include exceptions for legacy equipment where the performance may not be predictable due to a lack of modeling or inverter information.
- Second, not all current models are of the level of quality that they can be used to ensure that the plant will ride-through as specified in the standard. The implementation of this standard should consider the significant resources and cost to implement.
- Third, manufacturer support for GOs to ensure that IBRs only trip to prevent equipment damage as noted in R2.5 is limited for existing equipment and is unavailable for some legacy equipment. Additionally, this support has been very costly for us to obtain and will strain manufacturer resources to provide.

Considering these limitations, AESCE suggests that the SDT include exceptions for legacy equipment where 1. The performance may not be predictable due to a lack of accurate models at a reasonable cost, 2. Equipment limits may not be known or where the cost may be egregious to provide.

- Expectations for demonstrating and checking performance are unclear, please add language or examples to illustrate how the SDT believes this will happen.

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5

Answer	
Document Name	

Comment

Invenergy thanks the drafting team for their work and the opportunity to provide comments.

Regarding the proposed Implementation Plan for R6, six months may not be enough time to gather all applicable documentation regarding equipment limitations. There are a limited number of vendors of IBR technology that have serviced the industry, and they will be inundated with requests for documentation once the standard becomes effective.

On a final note, NERC appears to have borrowed from some of the requirements within IEEE 2800-2022 and brought them into this standard (e.g. the phase-angle jump requirement, etc.). Invenergy believes it would be incorrect to adopt such requirements until the work of IEEE Working Group p2800.2 has been completed and their recommended practice standard published. Without such an approved recommended practice standard, there is no industry-wide accepted set of procedures for verifying conformity to the borrowed requirements in PRC-029-1.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 1,3,6

Answer	
Document Name	

Comment

Ameren agrees with EEI's comments.

In addition, Ameren believes that ride-through requirements should be in a MOD standard instead of a PRC standard. Protection relay engineers do not have access to the necessary IBR equipment and do not have the expertise to determine the root cause of why an IBR behaved in an unexpected manner. Thus, evaluating and establishing a CAP to correct a reduction in power following a disturbance will not be performed by a relay engineer.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	
Document Name	

Comment

Invenergy thanks the drafting team for their work and the opportunity to provide comments.

Regarding the proposed Implementation Plan for R6, six months may not be enough time to gather all applicable documentation regarding equipment limitations. There are a limited number of vendors of IBR technology that have serviced the industry, and they will be inundated with requests for documentation once the standard becomes effective.

On a final note, NERC appears to have borrowed from some of the requirements within IEEE 2800-2022 and brought them into this standard (e.g. the phase-angle jump requirement, etc.). Invenergy believes it would be incorrect to adopt such requirements until the work of IEEE Working Group p2800.2 has been completed and their recommended practice standard published. Without such an approved recommended practice standard, there is no industry-wide accepted set of procedures for verifying conformity to the borrowed requirements in PRC-029-1.

Likes 0	
Dislikes 0	

Response

Brittany Millard - Lincoln Electric System - 5

Answer	
Document Name	

Comment

With regards to PRC-029 we woulkd ask:

1. Clarify and emphasize that limitations must not be construed as complete exemptions. If entities are unable to ride-through portions of the ride-through curve, this does not automatically exempt them from complying with the balance of the ride-through curve as described in the Technical Rationale. While this is clear in the Technical Rationale for Requirement R6 (page 9), this point needs to be brought out more clearly in the PRC-029 standard itself.

2. Expand PRC-029 to require Corrective Action Plans be implemented to remove equipment limitations within a specified timeline.

3. we recommend modifying Section 4 of PRC-029-1 as follows:

4. Applicability:

4.1 Functional Entities: 4.1.1 Generator Owner that owns equipment identified in section 4.2, 4.1.2 Transmission Owner that owns equipment as identified in section 4.2 Generator Owner that owns equipment identified in section 4.2.

4.2 Facilities: to include 4.2.3 Shunt static or dynamic reactive device(s) associated with IBR that either have or contribute to meeting the performance requirements.

4. The standard is event-based compliance that requires installing recorded equipment data with higher sampling rates at all applicable legacy IBR Facilities. Therefore, we suggest that the implementation plan for PRC-029 should be aligned with Project 2021-04 (PRC-028-1) for the legacy IBR. Also, we suggest having a different implementation plan for the legacy IBR from IBR connected after the approval date of PRC-029.

5. Some clarity on how these requirements would be enforced in the location where no data recording is available at the IBR facility during system events.

6. M1-M5 required GO to maintain the evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in Requirement R1-R5. What are the criteria for selecting the event(s) that should be analyzed to demonstrate compliance with the VRT, FRT, and VRT performance requirement(s)? If the performance does not meet the requirement(s), do Generator Owner needs to present a correction action plan and provide it to each applicable Reliability Coordinator. We suggest coordinate this project 2020-02 (PRC-029) with project 2023-02(PRC-030) regarding the IBR ride-through performance analysis.

7. We suggest that the drafting team ensure consistent language is used in the section 4.2 “Facilities” section with the other projects such as Project 2021-04 (PRC-028) and 2023-02(PRC-030). We suggested the following language be included in the applicability section. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

8. The title of the standard calls out “Inverter-Based Generating Resources”, should “Generating” be removed to be consistent?

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	
Document Name	

Comment

Several enhansments to PRC-029 are requested:

1. **Clarify and emphasize that limitations must not be construed as complete exemptions.** If entities are unable to ride-through portions of the ride-through curve, this does not automatically exempt them from complying with the balance of the ride-through curve as described in the Technical Rationale. While this is clear in the Technical Rationale for Requirement R6 (page 9), this point needs to be brought out more clearly in the PRC-029 standard itself.
2. **Expand PRC-029 to require Corrective Action Plans be implemented to remove equipment limitations within a specified timeline**.
3. **we recommend modifying Section 4 of PRC-029-1 as follows:**

4. Applicability:

4.1 Functional Entities: 4.1.1 Generator Owner that owns equipment identified in section 4.2, 4.1.2 Transmission Owner that owns equipment as identified in section 4.2 Generator Owner that owns equipment identified in section 4.2.

4.2 Facilities: to include 4.2.3 Shunt static or dynamic reactive device(s) associated with IBR that either have or contribute to meeting the performance requirements.

4. **The standard is event-based compliance that requires installing recorded equipment data with higher sampling rates at all applicable legacy IBR Facilities. Therefore, we suggest that the implementation plan for PRC-029 should be aligned with Project 2021-04 (PRC-028-1) for the legacy IBR. Also, we suggest having a different implementation plan for the legacy IBR from IBR connected after the approval date of PRC-029.**
5. **Some clarity on how these requirements would be enforced in the location where no data recording is available at the IBR facility during system events.**
6. **M1-M5 required GO to maintain the evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in Requirement R1-R5. What are the criteria for selecting the event(s) that should be analyzed to demonstrate compliance with the VRT, FRT, and VRT performance requirement(s)? If the performance does not meet the requirement(s), do Generator Owner needs to present a correction action plan and provide it to each applicable Reliability Coordinator. We suggest coordinate this project 2020-02 (PRC-029) with project 2023-02(PRC-030) regarding the IBR ride-through performance analysis.**
7. **We suggest that the drafting team ensure consistent language is used in the section 4.2 "Facilities" section with the other projects such as Project 2021-04 (PRC-028) and 2023-02(PRC-030). We suggested the following language be included in the applicability section. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.**

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

New terms are introduced on page 2 (Continuous **Operating** Region, Mandatory **Operating** Region, Permissive **Operating** Region). Requirement R1 includes the words "**operation** regions" and R2 includes the terms "Continuous **Operation** Region" (Part 2.1) and "Mandatory **Operation** Region" (Part 2.2). We recommend the drafting team review all instances of "**operation** region" within the standard and determine if it should be changed to "**operating** region" to align with the proposed terms. Or conversely, consider if the word "Operating" within the defined terms should be changed to "Operation".

For Requirement R2:

How will the Generator Owner or Transmission Owner of an applicable IBR be made aware that a PRC-029-1 applicable "System disturbance" has occurred within their associated Planning Coordinator(s) area(s)?

Part 2.1.2 refers to "requirements [for active or reactive power preference] specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator".

Part 2.2.2 refers to a “certain magnitude of reactive power response to voltage changes” or a preference for “active power priority instead of reactive power priority” that can be specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

Part 2.4 refers to a “lower post-disturbance active power level requirement” or “different post-disturbance active power restoration time” specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

With up to four registered entity types being able to provide these preferences (spanning the operations and planning time horizons), is there a chance the Generator Owner or Transmission Owner of an applicable IBR will receive conflicting requirements? Is there a corresponding standard(s) that includes a requirement(s) for the TP, PC, RC or TOP to specify these preferences?

For Requirement R3, how will the Generator Owner or Transmission Owner of an applicable IBR know that a PRC-029-1 applicable transient overvoltage period has occurred within their associated Planning Coordinator(s) area(s)?

For Requirement R4, how will the Generator Owner or Transmission Owner of an applicable IBR know that a PRC-029-1 applicable frequency excursion event has occurred within their associated Planning Coordinator(s) area(s)?

Requirement R6 requires that a Generator Owner or Transmission Owner of an applicable IBR that has a documented equipment limitation, that prevents it from meeting voltage ride-through requirements as detailed in Requirements R1 and R2, communicate each equipment limitation to their associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s). Since the Transmission Operator is also identified in R2, it seems strange to omit the TOP from R6.

With regard to the Implementation Plan, having PRC-024-4 becoming effective six months after approval is reasonable, since this Standard’s changes are primarily to limit its applicability to synchronous generators / condensers, and they should already be compliant with the existing version.

However, having PRC-029-1 become effective six months after approval is not reasonable. The technical rationale doesn't provide guidance on how to provide evidence of compliance. It can take considerable time to develop and perform the required analyses, generate potential design changes to make the required setting changes, and implement them.

We recommend providing implementation guidance or technical data showing how to demonstrate performance.

We also recommend allowing at least 24 months to achieve full compliance with the proposed requirements in PRC-029-1.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	
Document Name	

Comment

Black Hills Corporation supports EEI's and NAGF's additional comments.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
FirstEnergy finds inconsistency in how these newly created standards are applying IBR applicability in the Applicable Section – leading to confusion from one project and standard to another. We request these Drafting Teams align these Applicable Sections. FE cannot support the Implementation Plan until it is clear how R2 will be clarified toward requirement responsibility.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports comments provided by the NAGF	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	

Document Name	
Comment	

The language proposed in the Applicability section of PRC-029-1 is inadequate to define what IBR Facilities this Standard would apply to. The terms “BPS IBRs” and “IBR Registration Criteria” are too broad, vague, and undefined, and could include all IBRs interconnected to the Bulk Power System at any voltage level.

SMUD recommends the Standards Drafting Team use similar language to that proposed in NERC Standards Project 2021-04 Modifications to PRC-002 - Phase II, PRC-028-1 draft #2. If modified accordingly, the Applicability section would state:

“4.1. Functional Entities:

4.1.1. Generator Owner that owns equipment as identified in section 4.2

4.1.2. Transmission Owner that owns equipment as identified in section 4.2

4.2. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.”

Likes 0	
Dislikes 0	

Response

Brian Lindsey - Entergy - 1

Answer	
Document Name	

Comment

No Comment

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

NA	
Likes 0	
Dislikes 0	
Response	

Michael Brytowski - Great River Energy - 3	
Answer	
Document Name	
Comment	

1. Clarify and emphasize that limitations must not be construed as complete exemptions. If entities are unable to ride-through portions of the ride-through curve, this does not automatically exempt them from complying with the balance of the ride-through curve as described in the Technical Rationale. While this is clear in the Technical Rationale for Requirement R6 (page 9), this point needs to be brought out more clearly in the PRC-029 standard itself.

2. Expand PRC-029 to require Corrective Action Plans be implemented to remove equipment limitations within a specified timeline.

3.. **we recommend modifying Section 4 of PRC-029-1 as follows:**

4. Applicability:

4.1 Functional Entities: 4.1.1 Generator Owner that owns equipment identified in section 4.2, 4.1.2 Transmission Owner that owns equipment as identified in section 4.2 Generator Owner that owns equipment identified in section 4.2.

4.2 Facilities: to include 4.2.3 Shunt static or dynamic reactive device(s) associated with IBR that either have or contribute to meeting the performance requirements.

4. **The standard is event-based compliance that requires installing recorded equipment data with higher sampling rates at all applicable legacy IBR Facilities. Therefore, we suggest that the implementation plan for PRC-029 should be aligned with Project 2021-04 (PRC-028-1) for the legacy IBR. Also, we suggest having a different implementation plan for the legacy IBR from IBR connected after the approval date of PRC-029.**

5. **Some clarity on how these requirements would be enforced in the location where no data recording is available at the IBR facility during system events.**

6. M1-M5 required GO to maintain the evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in Requirement R1-R5. What are the criteria for selecting the event(s) that should be analyzed to demonstrate compliance with the VRT, FRT, and VRT performance requirement(s)? If the performance does not meet the requirement(s), do Generator Owner needs to present a correction action plan and provide it to each applicable Reliability Coordinator. We suggest coordinate this project 2020-02 (PRC-029) with project 2023-02(PRC-030) regarding the IBR ride-through performance analysis.

7. We suggest that the drafting team ensure consistent language is used in the section 4.2 “Facilities” section with the other projects such as Project 2021-04 (PRC-028) and 2023-02(PRC-030). We suggested the following language be included in the applicability section. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

BC Hydro appreciates the drafting team’s efforts and the opportunity to comment, and offers the following:

1. The Applicability section (A.4.2 Facilities) of PRC-029-1 references BPS IBR and IBR Registration Criteria. BC Hydro suggests that the Facilities section instead use wording reflective of the proposed Category 2 GO as included in the recent revisions to the NERC Rules of Procedure.
2. BC Hydro suggests that the use of “shall” in the language of the Measures may not be appropriate as it could imply a new Requirement or expansion on the existing Requirement. The obligation of having evidence is adequately established and enforceable via the CMEP.
3. The Measure M3 of PRC-029-1 references "the associated Planning Coordinator". The associated Requirement R3 does not. BC Hydro suggests that this is not needed as there may be switching events within a PC's area that do not create overvoltage conditions to trigger R3 for certain IBRs within the PC area.

Likes 0	
Dislikes 0	

Response

Helen Lainis - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment

Applicability:

In Introduction, Section 4.2.2, it is not obvious what aspect of 'IBR Registration Criteria' makes an IBR an 'applicable' IBR – is it simply that an IBR meets NERC Registration Criteria? This bullet point should be elaborated to ensure clarity.

Event-Based Standard:

The IESO has concerns with this standard being an event-based standard, in that it does not necessarily provide an assurance of reliability before events occur, such as would be provided by having an engineering analysis, or bench-testing/real-time simulations of controls equipment that indicates successful ride through of prescribed disturbances is expected.

Without disturbance events that challenge the IBRs to perform properly it would be unknown if the IBR is compliant. At a minimum, the measures (e.g, M2-M5) should be extended to allow a statement that no such events are known to have occurred to 'count' as evidence of compliance.

Presentation of Ride Through Ranges:

The intended ride through requirements could be made more clear if the 'minimum ride through times' were associated with precisely stated, *non-overlapping ranges* of voltages or frequencies, such as in the example 'Table 2' provided by the IESO in the comments above, for Section 2.1.

Nominal Voltages:

To ensure clarity of intent in note #4 of Attachment 1, the 'nominal' system voltage values should be listed as they are in the existing PRC-024, i.e., "(e.g., 100 kV, 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 400 kV, 500 kV, 765 kV, etc.)"

Harmonize Tables, Figures, Requirements:

The levels of voltage/frequency excursion and the minimum ride through times for all tables, figures, and any associated performance requirements that modify the requirements at given times should be carefully reviewed and harmonized. There are presently some conflicting entries in the tables/figures.

Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	

Response

Chantal Mazza - Hydro-Quebec (HQ) - 1 - NPCC

Answer	
Document Name	

Comment

We are concerned that the standard refers to a defined term for IBR which has yet to be adopted in project 2020-06.

We suggest that the drafting team ensure consistent language is used in the section 4.2 "Facilities" section with the other projects such as 2021-04 (PRC-028) and 2023-02(PRC-030). Section 4.2.2 refers to IBR Registration criteria, however it is our understanding that section 4.2.1

would refer to GOs and TOs “that own equipment as identified in section 4.2” and where section 4.2 would indicate “the Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.” .

We question why “attachment 1” and “Requirement R6” are written in bold.

Attachment 1: should the “including, but not limited to” in table 2 include the same list (or minimally the same wording) that is found in the technical rationale of the IBR definition in project 2020-0?. For example, the IBR list in 2020-06 refers to “solar photovoltaic” whereas table 2 refers to “photovoltaic (PV)”.

In what standard does the PC/TP define the applicable table in point 3 of section 2 in attachment 1? Same question for the voltage base for per unit calculation in both Attachment 1 and 2. Is there a corresponding requirement in another standard that requires the PC/TP to do this?

· Terms : Mandatory and permissive operation should be defined based on the attachment figures allowing for interconnections to use different requirements

· A-4.2.2 What is the IBR registration criteria? Add a clear reference and make sur the user understands what the IBR registration criteria is.

· B-R2-2.1 Attachment 1 only uses "no-trip zone". Define continuous operating region more clearly in the table (similar to what is done in PRC-024-4)

· B-R2-2.1.2 Can the TP ask for a mix of active/reactive power based on a predetermined ratio (currently only indicated as active or reactive).

· B-R2-2.2 Attachment 1 only uses "no-trip zone". Define "mandatory operation region" in Attachment 1.

· B-R2-2.4 Permissive operation region is not used or defined in attachment 1.

· B-R3. The document refers to an overvoltage value of 1.2pu. It should refer to a voltage exceeding the mandatory operating region in order for Interconnections to set their own overvoltage table.

· B-R3. Since R6 does not apply to this requirement, what will be done with existing IBR that cannot ride through these overvoltages ? An exemption clause is required for existing IBR that cannot be modified or upgraded.

· B-R4. The 5Hz/s value should be moved to Attachment 3 and B-R4 should only refer to the value in the Attachment.

· B-R4. Since R6 does not apply to this requirement, what will be done with existing IBR that cannot ride through these frequencies and ROCOF ? (for instance, for all the HQ connected projects, the ROCOF requirement was 4Hz/s) An exemption clause is required for existing IBR that cannot be modified or upgraded.

· B-R5. Since R6 does not apply to this requirement, what will be done with existing IBR that cannot ride through this phase angle jump ? An exemption clause is required for existing IBR that cannot be modified or upgraded.

· Attachment 1. Tables 1 and 2: Indicate what is considered as “continuous operation”, “mandatory operation” and “permissive operation” in an additional column.

· Attachment 1. HQ needs a Quebec regional variance since the Québec Interconnection has its own requirements in this regard.

· Attachment 2. Bullet 3: This sentence is hard to read. Proposed replacement: "Each IBR shall not trip unless the cumulative time of one or more instances in which the instantaneous voltage exceeds the respective voltage threshold over a 1-minute time window exceeds the minimum ride-through time"

· Attachment 2. HQ needs a Quebec regional variance since the Québec Interconnection has its own requirements in this regard.

· Attachment 3. This attachment should also include the maximum absolute ROCOF value.

· Attachment 3. HQ needs a Quebec regional variance

· B-R2-2.1.2 Which entity between Transmission Planner, Planning Coordinator, Reliability Coordinator and Transmission Operator has priority to specify those requirements?

· B-R2-2.4 Which entity between Transmission Planner, Planning Coordinator, Reliability Coordinator and Transmission Operator has priority to specify those requirements?

Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

- Evidence Retention: We would suggest that the evidence retention period for both Standards should be changed from five years to three years, to be consistent with other NERC Standards.

- The standard is event-based compliance that required installing recorded equipment data with higher sampling rates at all applicable legacy IBR Facilities. Therefore, we recommend that the implementation plan for PRC-029 should be aligned with Project 2021-04 (PRC-028-1) for the legacy IBR. Also, we suggest have different implementation plan for the legacy IBR from IBR connected after the approval date of PRC-029.

- Some clarity how these requirements would be enforced in a location where no data recording is available at an IBR facility during system events.

- M1-M5 required the GO to maintain the evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in Requirement R1-R5. What are the criteria for selecting the event(s) that should be analyzed to demonstrate compliance with the VRT, FRT and VRT performance requirement(s)? If the performance does not meet the requirement(s), do Generator Owner need to present a corrective action plan and provide it to each applicable Reliability Coordinator. We suggest coordinating this project 2020-02 (PRC-029) with project 2023-02(PRC-030) regarding the IBR ride-through performance analysis.

- R2: We agree with the present flexibility that some of the IBR VRT performance could be modified to meet the individual system needs by the applicable Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator. However, some clarity may be required on how this process is initiated and what type of evidence is required to demonstrate the request is received and implemented. This may be an additional requirement assigned to the Transmission Planner. Each Transmission Planner, Planning Coordinator, and Transmission Operator that jointly specifies the following voltage ride-through performance requirements within their area(s) different than those specified under R2, shall make those requirements available to each associated applicable IBR Generator Owner and Transmission Owner.

- We suggest that the drafting team ensures consistent language is used in the section 4.2 "Facilities" section with the other projects such as Project 2021-04 (PRC-028) and 2023-02(PRC-030). We suggest the following language be included in the applicability section. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

- R3: we suggest adding to the attachment 2 how the instantaneous transient overvoltage should be calculated (such as what is the pu based on? and the minimum sampling rate?)

Likes 0	
Dislikes 0	

Response

Leah Gully - Madison Fields Solar Project, LLC - 5 - RF

Answer	
Document Name	

Comment

1. The proposed Standard refers to four different operating regions (no-trip zone, Continuous Operation Region, Mandatory Operation Region, and Permissive Operating Region). The different zones require Generator Owners to take different actions based on the number of disturbances and deviations that occur within in a 10 second period as well as the positive sequence voltage on the high side of the MPT. The ability of plant operators or inverter controls to identify, track, and respond effectively to all these variables is unrealistic. Why are these requirements not applied to non-IBR owners?
2. In R1, GOs are required to ensure that IBRs continue to "exchange current in accordance with the no-trip zones and operation regions as specified in Attachment 1." The Standard does not define the term "exchange current". Please define this term.
3. Measure 1 requires the Generator Owner and Transmission Owner to have actual recorded data for each applicable IBR demonstrating ridethrough adherence. This measure needs a timeframe for retention of the data.
4. The second half of the sentence in 2.1.1 doesn't appear to add any value to the sub-requirement. Please clarify what added operational requirement is meant by, "…and continue to deliver active power and reactive power up to its apparent power limit."
5. Requirement R2.1.2 allows four different entities to dictate each IBR's operating mode. This contradicts the requirements of VAR-001 which states that GOs must operate in voltage control mode unless exempted by the TOP. Recommend selecting one of these entities to determine the preference.

6. For overvoltage conditions greater than 140% Attachment 2 requires Generator Owners to distinguish and respond with different time delays, all less than or equal to 3 ms. Recommend requiring IBRs to delay their response to voltage excursions and program their IBRs to match the responses of synchronous machines.
7. Clarify Requirement 2.2.1 to address the expected operational response to close-in faults. Recommend the Standard specify separate performance requirements for close-in faults and more distant faults.
8. Requirement 2.2 appears to mandate that IBRs who operate in active power priority mode in the continuous operating region would be required to switch to the reactive power mode if a voltage disturbance occurs. What criteria are IBRs expected to use to determine when this switch should occur? What are IBRs expected to do if their inverters cannot be switched without software modifications?
9. The ride through requirements should all be specified in the same units of time.
10. Couldn't the voltage overshoot concerns addressed by Requirement 2.3 be addressed more reliably by slowing the response time of the IBR plant controllers to match that of synchronous generation?
11. Measure 2 requires the GO and TO to have actual recorded data during each system disturbance. Recommend establishing a timeframe for the retention of this data.
12. Measure 3 requires the GO and TO to have actual recorded data during each transient voltage event. Recommend establishing a timeframe for the retention of this data.
13. Measure 4 requires the GO and TO to have actual recorded data during each frequency excursion event. Recommend establishing a timeframe for the retention of this data.
14. Measure 5 requires the GO and TO to have actual recorded data during each positive sequence voltage phase angle changes that are less than 25 electrical degrees at the high side of the main transformer. Recommend establishing a timeframe for the retention of this data.
15. Requirement 6 has more specific requirements for an equipment limitation than is being proposed for the synchronous generators. Recommend PRC-029 reflect the wording proposed for PRC-024-4.
16. PRC-029 frequency ride-through is a single graph for all regions. The graph no trip zone is larger than the existing PRC-024 frequency no-trip zone for Eastern, Western, and ERCOT zones. The wording in the rationale is very soft (may be required). The change will cause the LFRT and HFRT settings to be updated as well as collector and transformer frequency settings. Recommend the frequency settings remain consistent with PRC-024 until the time that it is justified from grid events.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	
Document Name	

Comment

In some cases, the initial 6-month implementation period to develop a technical rationale for an exemption may be too short. This is attributable to the necessary input from the original OEM and in some cases due to the complexity associated with facilities comprised of new and old equipment. One example where this may exist are plants where a repower project may have taken place that does not replace all inverters. In a case such as this, the new equipment may meet the requirements, but the remaining existing equipment may not. This may require a detailed study to verify compliance, or perhaps instead, require some form of hybrid exemption for the site. Unlike the stated technical goal of the standard where this is a "performance based" standard, the justification for a technical exemption will require some form of a study to justify that exemption. This could lead to a greater than 6-month period in developing the exemption request. To accommodate these situations, AEP recommends an implementation period of 18 months.

PRC-029 requires that IBR's shall ride through 110%-120% overvoltage from 0-1 seconds as seen at the high side of the main power step-up transformer. Due to voltage drop, the voltage seen at the equipment terminals can be another 5% higher leading to potential equipment damage from overvoltage. AEP suggests that the SDT consider lowering the ride through to 110% at the high side of the main step-up transformer.

Likes 0	
Dislikes 0	
Response	
Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	2020-02_EPRI Comments on Draft NERC PRC-029 (IBR ride-through) Reliability Standard.pdf
Comment	
Likes 0	
Dislikes 0	
Response	