Comment Report

Project Name: 2023-01 EOP-004 IBR Event Reporting | Draft 2

Comment Period Start Date: 2/12/2024

Comment Period End Date: 3/27/2024

Associated Ballots:

There were 42 sets of responses, including comments from approximately 134 different people from approximately 87 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the language proposed in EOP-004-5 Attachment 1 as proposed, or with non-substantive changes? If you do not support EOP-004-5 Attachment 1 as proposed, please explain the changes that, if made, would result in your support.

2. The Standard Drafting Team (SDT) proposes a two (2) year implementation plan for EOP-004-5. Do you agree with the proposed implementation plan? If you do not support the implementation plan as proposed, please explain the changes that, if made, would result in your support.

3. The SDT believes the language of EOP-004-5 addresses the issues outlined in the SAR in a cost-effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost-effective approaches, please provide your recommendation and, if appropriate, technical, or procedural justification.

4. Provide any additional comments on the standard and technical rationale for the DT to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1,3,5	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO

					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
WEC Energy Group, Inc.	Christine Kane	3,4,5,6		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
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
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

					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Kris Carper	Arizona Electric Power Cooperative, Inc.	2	WECC
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	SERC
Entergy	Julie Hall	1,3,6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	SERC
Electric Reliability Council of Texas, Inc.	Kennedy Meier	2		ISO/RTO Council Standards Review Committee (SRC)	Darcy O'Connell	California ISO	2	WECC
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Joshua Phillips	Southwest Power Pool, Inc. (RTO)	2	MRO
					Helen Lainis	Independent Electricity System Operator	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
FirstEnergy - FirstEnergy Corporation	Mark Garza	1,3,4,5,6		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Pacific Gas and Electric Company	Michael Johnson	1,3,5	WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC

					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					Frank Lee	Pacific Gas and Electric Company	5	WECC
Black Hills Corporation	Rachel Schuldt	1,3,5,6		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
					Alain Mukama	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					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
					John Pearson	ISO New England, Inc.	2	NPCC
					Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC

Randy MacDonald	New Brunswick Power Corporation	2	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
David Burke	Orange and Rockland	3	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
David Kwan	Ontario Power Generation	4	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
Glen Smith	Entergy Services	4	NPCC
Sean Cavote	PSEG	4	NPCC
Jason Chandler	Con Edison	5	NPCC
Tracy MacNicoll	Utility Services	5	NPCC
Shivaz Chopra	New York Power Authority	6	NPCC
Vijay Puran	New York State Department of Public Service	6	NPCC
ALAN ADAMSON	New York State Reliability Council	10	NPCC
David Kiguel	Independent	7	NPCC

					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Mia Wilson	Southwest Power Pool Inc.	2	MRO
					Josh Phillips	Southwest Power Pool Inc.	2	MRO
					Josh Pope	Southwest Power Pool Inc	2	MRO
					Jim William	Southwest Power Pool Inc.	2	MRO
					Randy Cleland	Southwest Power Pool Inc.	2	MRO
					Heather Harris	Southwest Power Pool Inc.	2	MRO
					Derek Hawkins	Southwest Power Pool Inc.	2	MRO
					Scott Aclin	Southwest Power Pool Inc.	2	MRO
					Brett Springfield	Southwest Power Pool Inc.	2	MRO
					Margaret Quispe	Southwest Power Pool Inc.	2	MRO
					Bryan Wood	Southwest Power Pool Inc.	2	MRO
					Ashley Striger	Southwest Power Pool Inc	2	MRO
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC

1. Do you agree with the language proposed in EOP-004-5 Attachment 1 as proposed, or with non-substantive changes? If you do not support EOP-004-5 Attachment 1 as proposed, please explain the changes that, if made, would result in your support.

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment

Delete footnote 1 and modify IBR generation loss Threshold for Reporting as shown below:

An unexpected loss of aggregated generation ≥ 500 MW, occurring over 15 seconds or less, from NERC registered Inverter-Based Resources (IBRs) directly connected to the Bulk Power System at 60kV and above and with an individual or aggregate output of greater than or equal to 20 MVA.

IBR generation loss shall be calculated by the BA using Telemetering data from IBR generators within its Balancing Authority Area (including, at a minimum, BES-connected IBRs, and BPS-connected IBRs directly connected to the Bulk Power System at 60 kV and above and with an individual or aggregate output of greater than or equal to 20 MVA for which the BA has Telemetering data). This calculation involves subtracting the lowest aggregated IBR generation output, occurring within a 30-second period following a Contingency, from the pre-Contingency aggregated IBR generation output averaged over the most recent 2-minute period.

The Responsible Entity is not required to report losses due to weather patterns, lack of wind, change in irradiance, fuel unavailability, curtailment, ramping, planned outage, planned testing, failure of SCADA or Telemetering data, or due to the loss of a radial transmission facility that disconnects the IBR generators.

The time periods (15 seconds for loss, and 2 minutes for comparison) are arbitrary, open to any suggestions on what a reasonable timeframe would be. We just wanted to capture the idea of needing to define the timeframes of concern on these.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE

Answer	No
Document Name	

Comment

PNMR supports the changes recommended by EEI for Question 1.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	

Comment

AEPC signed on to ACES comments:

We at ACES appreciate the effort put forth by the SDT to incorporate Inverter-Based Resources into the EOP-004 Reliability Standard; however, we have some minor concerns with the currently proposed language in Attachment 1.

Per the Technical Rationale, given the volatile nature of IBRs, the SDT intended to utilize a narrower event window for determining when a true IBR generation loss Event Type occurs. We agree with this approach; however, we believe that it should be more explicitly and definitively expressed within the Threshold for Reporting. In other words, we believe that the IBR generation loss Event Type should have an explicitly defined period akin to the “within one minute” parameter defined in the Generation loss Event Type Threshold for Reporting.

Furthermore, we do not believe that the use of the NERC defined term “Contingency” fully encapsulates the intent of the SAR. Contingency is defined in the NERC Glossary of Terms as follows:

“The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.”

It is the opinion of ACES that there are many factors that could potentially cause an IBR generation loss >= 500 MW beyond an unexpected failure or outage of a system component. This is in fact enumerated in the Consequential/non-consequential interruption (generation loss) section of the Technical Rationale. In other words, a control system responding to perturbations in voltage and/or frequency on the Interconnection does not constitute a failure of the control system nor does it necessarily result in an outage of the IBR. For example, when responding to an over-frequency event, the initial response of the control system will generally be implemented via “droop control” resulting in a reduction in MW production. If this initial response is sufficient to mitigate the over-frequency event, then an IBR generation loss >= 500 MW may occur with zero outages.

Lastly, due to the extremely variable output of IBRs, we believe that the calculation to determine the quantity of IBR generation loss should utilize an average value of aggregated IBR generation. It is our opinion that using average aggregated IBR generation values over a given time period will aid the BA in more efficiently identifying reportable events.

Thus, we recommend utilizing language much like the following for IBR generation loss Threshold for Reporting:

An unexpected loss, within 30 seconds, of aggregated generation ≥ 500 MW from Inverter- Based Resource(s) directly connected to the Bulk Power System (BPS).

IBR generation loss shall be calculated by the BA using Telemetering data from IBR generators directly connected to the BPS within its Balancing Authority Area for which the BA has Telemetering data. This calculation involves subtracting the current average aggregated IBR generation output over a rolling 30-second period from the average aggregated IBR generation output during the previous 30-second period immediately preceding the current period (i.e.: IBRcur-avg - IBRprev-avg).

The Responsible Entity is not required to report losses due to weather patterns, lack of wind, change in irradiance, fuel unavailability, curtailment, ramping, planned outage, planned testing, failure of SCADA or Telemetering data, or due to the loss of a radia transmission facility that disconnects the IBR generators.

Likes 0	

Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments offered by EEI.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the MRO NSRF on question #1.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

The NAGF does not agree with the proposed Inverter-Based Resources (IBR) language in EOP-004-5 Attachment 1 per the following concerns:

a. The NAGF does not agree with use of the term "sudden" and recommends that it be replaced with a defined time period such as "30 seconds".

b. The NAGF does not agree with the proposed IBR aggregate generation threshold >= 500 MW. We believe that such a low threshold will place a significant burden on Balancing Authorities (BAs) and Generator Owners/Generator Operators (GOs/GOPs) to analyze/confirm reportable IBR events *especially as additional IBR facilities are commissioned. Therefore, the NAGF recommends that the Standards Drafting Team consider implementing a graduated IBR aggregated generation threshold such as:*

500 MW for years 0-2

750 MW for years 3-5

1000 MW for years 6-8

c. The NAGF notes that the proposed exclusion language does not cover all exceptions. We recommend that the SDT consider adding language to cover intentional cessation of generation, technical or regulatory constraints, and use of the term "OEM designed operations".

Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
Dislikes 0	

Response

Alison MacKellar - Constellation - 5,6

Answer	No
Document Name	

Comment

Constellation supports NAGF comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6.

Likes 0	
Dislikes 0	

Response

Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	No
Document Name	

Comment

Supporting EEI's comments.

Likes 0	
Dislikes 0	

Response

Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	No
Document Name	

Comment

Support EEI comments.

Likes 0	
Dislikes 0	

Response

Peter Yost - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	No
Document Name	

Comment

Supporting EEI comments for all questions.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

PJM appreciates and supports the Drafting Team's additional detailed language associated with IBR loss reporting, however, does not agree with the low threshold of IBR generation loss reporting. Our preference is to keep the current generation loss threshold of equal to or greater than 2,000 MWs; and if this is not possible, request similar disposition of thresholds (within the Standard) based on Interconnection. Standards that include Interconnection specific thresholds include and are *not* limited to: EOP-004 already includes different generation loss reporting for the ERCOT Interconnection as compared to the Eastern/Western/Quebec Interconnections; and different thresholds are included in the NERC definition: Reportable Balancing Contingency Event (• Eastern Interconnection – 900 MW • Western Interconnection – 500 MW • ERCOT – 800 MW • Quebec – 500 MW). This request is primarily due to the larger BA footprints in the Eastern Interconnection and in some areas the larger IBR current and future Projects. As a result, PJM requests threshold reporting consistency of Reportable Balancing Contingency Events (900 MWs in the Eastern Connection) – with the preference of keeping the currently established >2,000 MW.

Likes 0	

Dislikes 0	
Response	
Helen Wang - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No
Document Name	
Comment	
Per EEI comments.	
Likes 0	
Dislikes 0	
Response	
Andrew Smith - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AZPS agrees with comments submitted by EEI on behalf of its members that the IBR definition should be approved prior to proposing changes to a Reliability Standard, not contained in a foot note, or referencing a currently unapproved definition in another SDT project. AZPS supports EEI's comments around using the reference to sudden loss being too ambiguous in the Threshold for Reporting section and support their proposed language suggestions.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI does not support the proposed language in EOP-004-5 Attachment 1 for IBR generation loss for the following reasons:

- Definitions should not be contained in footnotes of Reliability Standards. Moreover, an unapproved definition emanating from another SDT should not be included, contained, used, or otherwise referenced in a proposed Reliability Standard. While we understand that a clear understanding of what is meant by the term “Inverter-Based Resource” is fundamental for entity compliance with this standard, inclusion of this unapproved definition adds unnecessary confusion and should not be included in any part of this Standard. To address this concern, we suggest that the SDT simply capitalize the term and seek approval for this Reliability Standard after the approval of the IBR definition being developed by the Project 2020-06 SDT.

- We do not support detailed lists of exclusions within the threshold section. It is sufficient to identify exclusions at a high level. Details can be provided within the technical rationale to assist BA in the development of their processes and procedures for identifying IBR generation loss events.
- We do not support language such as sudden loss because it is too ambiguous.

To address our concerns, we offer the following language as an alternative to the IBR generation loss “Threshold for Reporting” that appears in the currently proposed drat of EOP-004-5 (changes are identified in bold face):

Threshold for Reporting (IBR generation loss)

The unexpected loss of aggregated **Inverter-Based Resource(s)** ≥ 500 MW **within a defined Balancing Authority Area within 30-seconds after a system Disturbance. Those losses:**

- **Shall be totaled exclusively from telemetry data as monitored by the responsible BA; and**
- **Based on the difference between the lowest aggregated IBR generation output (within 30-seconds) following a system Disturbance and the pre-Disturbance aggregated IBR output; but**
- **Shall not contain any IBR losses due to weather, planned testing/outages, failure of SCADA/Telemetering equipment or due to the loss of any radial transmission facility disconnecting IBR resources.**

Likes 2	Tim Kelley, N/A, Kelley Tim; Jennie Wike, N/A, Wike Jennie
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

The following language in Attachment 1 (IBR generation loss event / “Threshold for Reporting” column) is unclear -- “(including, at a minimum, BES-connected IBRs, and BPS-connected IBRs for which the BA has Telemetering data)”. Is it the drafting team’s intent that **all** BES-connected IBRs (that meet Inclusion I4 of the BES definition) provide telemetered data to their BA, and that the BA shall include all telemetered data from those facilities in their calculation at a minimum? And that the BA’s minimum required calculation be supplemented with any BPS-connected IBRs (that don’t meet Inclusion I4) that provide telemetered data to the extent available?

In addition, the term “BES-connected IBRs” is not a defined term and could be interpreted in different ways. Given that a significant amount of IBR generation in a Balancing Authority Area is often not visible to the BA, the standard needs to be very clear on exactly what the requirement is for inclusion in the calculation. This ambiguity could cause some entities to incur significant expense to add telemetry to IBR facilities which was not intended in the Standard.

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

We at ACES appreciate the effort put forth by the SDT to incorporate Inverter-Based Resources into the EOP-004 Reliability Standard; however, we have some minor concerns with the currently proposed language in Attachment 1.

Per the Technical Rationale, given the volatile nature of IBRs, the SDT intended to utilize a narrower event window for determining when a true IBR generation loss Event Type occurs. We agree with this approach; however, we believe that it should be more explicitly and definitively expressed within the Threshold for Reporting. In other words, we believe that the IBR generation loss Event Type should have an explicitly defined period akin to the "within one minute" parameter defined in the Generation loss Event Type Threshold for Reporting.

Furthermore, we do not believe that the use of the NERC defined term "Contingency" fully encapsulates the intent of the SAR. Contingency is defined in the NERC Glossary of Terms as follows:

"The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element."

It is the opinion of ACES that there are many factors that could potentially cause an IBR generation loss >= 500 MW beyond an unexpected failure or outage of a system component. This is in fact enumerated in the Consequential/non-consequential interruption (generation loss) section of the Technical Rationale. In other words, a control system responding to perturbations in voltage and/or frequency on the Interconnection does not constitute a failure of the control system nor does it necessarily result in an outage of the IBR. For example, when responding to an over-frequency event, the initial response of the control system will generally be implemented via "droop control" resulting in a reduction in MW production. If this initial response is sufficient to mitigate the over-frequency event, then an IBR generation loss >= 500 MW may occur with zero outages.

Lastly, due to the extremely variable output of IBRs, we believe that the calculation to determine the quantity of IBR generation loss should utilize an average value of aggregated IBR generation. It is our opinion that using average aggregated IBR generation values over a given time period will aid the BA in more efficiently identifying reportable events.

Thus, we recommend utilizing language much like the following for IBR generation loss Threshold for Reporting:

An unexpected loss, within 30 seconds, of aggregated generation ≥ 500 MW from Inverter-Based Resource(s) directly connected to the Bulk Power System (BPS).

IBR generation loss shall be calculated by the BA using Telemetering data from IBR generators directly connected to the BPS within its Balancing Authority Area for which the BA has Telemetering data. This calculation involves subtracting the current average aggregated IBR generation output over a rolling 30-second period from the average aggregated IBR generation output during the previous 30-second period immediately preceding the current period (i.e.: IBRcur-avg - IBRprev-avg).

The Responsible Entity is not required to report losses due to weather patterns, lack of wind, change in irradiance, fuel unavailability, curtailment, ramping, planned outage, planned testing, failure of SCADA or Telemetering data, or due to the loss of a radial transmission facility that disconnects the IBR generators.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy feels this standard should not have a separate definition of IBR and asks the DT to consider pausing this draft until the IBR Definition becomes official under Project 2020-06.

Similar to the NERC Project 2015-09 Establish and Communicate System Operating Limits, FirstEnergy feels combining all Projects related to IBR topic would be better suited to be successful in the operations and security of IBRs and their operations and that this would provide clear direction to industry.

FirstEnergy remains concerned on the 500mw threshold. We ask what other thresholds of Generation Loss were considered by the DT and how much change in reporting responsibility would be affected.

Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	No
Document Name	
Comment	

The definition of Inverter-Based Resource in the footnote is inconsistent with the announcement (dated 2/23/2024) as follows: "**Inverter-Based Resource (IBR):** A plant/facility that is connected to the electric system consisting of one or more IBR Unit(s) operated as a single resource at a common point of interconnection. IBRs include, but are not limited to, solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell." Good to see the footnote will be removed when finalized but as is voting may be based on what definition is included in this Standard which, when finalized, may be affected when finalized. Suggest changing the event type to "IBR loss" as generation may be (or should be) considered in the development of the IBR definition as shown above in the "announced" definition. Suggest changing the threshold to recognize the idea that "telemetry" may not be directly from the IBR as follows "IBR loss shall be calculated by the BA using Real-time data representing IBR output….." Note that the definition of Balancing Authority Area indicates BPS-connected IBRs are within the "metered boundaries" of a BA. Use of Glossary term "Telemetering" may be inappropriate based on the definition-" The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations."

SDT should provide clarity in what "planned outage" and "planned testing" entails to avoid events caused by a planned Facility outage or planned testing at a transmission facility that causes a 500 MW outage of IBRs may inadvertently not be reported because of the language. It is assumed (or could be) that the language is applicable to an IBR.

"Loss of the radial transmission facility" for an IBR greater than 500 MWs should not be considered non-reportable. The loss is an event and the impact is the same for a 500 MW loss caused by a radial line or two lines. If the "radial transmission facility" loss is due to a misoperation that causes lower frequency (or voltage) due to loss of 500 MWs of IBRs and subsequently trips 400 MWs of IBRS (either as a result of low frequency/voltage or the misoperation)---this would not be considered a reportable event even though 900 MWs were lost, correct?

"Generation loss" does not include the caveats noted for IBRs. Is the SDT addressing that threshold for reporting criteria (includes early attempts at IBR capture) for "Generation loss"? It would be prudent to report all generation loss (IBR and synchronous) due to a cold weather pattern impacting a large part of the BA footprint.

"Loss of DC Tie Line" contains undefined term and may not capture an event effectively. SDTs have not been consistent in describing direct current (DC or dc) -PRC-023-4/5/6 all use "dc lines" and "dc converter transformers". PRC-026-1/2 both use "direct current (dc) lines" and "dc converter transformers". TPL-001-5.1 uses "DC Transmission controllers" and "DC line". BAL-001-TRE-2 uses "DC Tie Providing Ancillary Services". Suggest not adding inconsistency by utilizing a "new" undefined term. Consider either of these suggestions- Event Type- "Loss of DC" Threshold for Reporting- "Loss of ≥ 500 MW DC flow between two separate asynchronous systems." OR Event type "Loss of DC capability or availability" Threshold for Reporting- "Loss of DC capability or availability of ≥ 500 MW between two separate asynchronous systems." Understand the SDT can not correct other inconsistencies in other Standards, but the SDT should avoid introducing a new term that may not actually capture other considerations by other SDTs. If the "dc converter transformer" relays or the "DC Transmission controllers" do not cause the loss of a "DC Tie Line" an event may not be reported because of the language.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment

MISO appreciates the Standard Drafting Team's (SDT) consideration of our past comments and supports the additional language in Attachment 1 clarifying when IBR generation loss reporting is not required.

That said, MISO does not support the ≥ 500 MW threshold for IBR generation loss reporting. MISO requests a threshold of ≥ 2,000 MW for the Eastern Interconnection. This aligns with the existing threshold for reporting "Generation loss" events in the Eastern Interconnection. While lower thresholds may be appropriate for the Western, Quebec and ERCOT Interconnections, this is not reasonable in the Eastern Interconnection, particularly considering the number of individual IBRs ≥ 500 MW that are large enough to trigger the reporting requirement on their own. With the influx of IBRs interconnecting in MISO's footprint, this low of a threshold will require a substantial time commitment: first, to identify, verify and report the event and second, to support the anticipated Event Analysis that will follow.

MISO recognizes that it is not the SDT's intent to require event reporting due to the loss of a single IBR facility. Nevertheless, it will take Balancing Authorities time and resources to research each loss of ≥ 500 MW from IBRs to ascertain whether the event must be reported or not. In light of the tight timeline for reporting, this places a heavy administrative burden on Balancing Authorities and will pull resources from managing real-time reliability issues to researching administrative, compliance issues. While over reporting is not penalized, doing so will only increase the amount of after-the-fact activity a BA will be required to perform in support of Event Analysis.

The Interconnection-specific approach that MISO is proposing aligns well with what is currently used in several other, existing NERC standards, including that for Reportable Balancing Contingency Events.

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	
Southern Company supports the EEI comments.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
BC Hydro appreciates the drafting team's clarifications during the March 12, 2024 that the Footnote 1 will be removed and appropriate wording will be used (both in the Standard and the Technical Rationale) to reference the IBR definition(s) subsequent to its development under the NERC Project 2020-06 as a new NERC Glossary Term. Please confirm our understanding or provide any additional clarifications as appropriate.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

1 - BPA suggests the Attachment 1 language for the Event Type **Loss of DC Tie Line** column 'Threshold for Reporting' be modified.

from: Loss of DC Tie Line, between two separate asynchronous systems, loaded at ≥ 500 MW.

to: Complete loss (both poles) of a DC Tie Line between two separate asynchronous systems, loaded at ≥ 500 MW, excluding automatic restart events.

2 - The corresponding language in Attachment 2, 4. Event Identification and Description should also be changed to **Complete** Loss of DC Tie Line.

3 – BPA appreciates the revisions to 1 Event Type IBR generation loss Threshold for Reporting and proposes that the corresponding language in Attachment 2, 4. Event Identification and Description should also be changed to **Unexpected** IBR generation loss.

Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	Yes
Document Name	
Comment	

Constellation supports NAGF comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	

Answer	Yes
Document Name	
Comment	
The ISO/RTO Council (IRC) Standards Review Committee (SRC), which consists, for purposes of these comments, of CAISO, ERCOT, IESO, ISO-NE, and SPP, supports the language in Attachment 1 as currently drafted, but believes that the Loss of DC Tie Line section of Attachment 1 may be unclear. The Threshold for Reporting for a Loss of DC Tie Line event is currently "Loss of a DC Tie Line . . . loaded at ≥ 500 MW." This language could be understood to mean that only full losses of a DC Tie must be reported, while partial losses do not need to be reported. In other words, if a DC Tie loaded at 900 MW suddenly drops to 300 MW, it is unclear whether this would be considered a "[l]oss of a DC Tie Line" that must be reported. If the partial loss of a DC Tie is not required to be reported, the SRC recommends that this be clarified in the Threshold for Reporting in Attachment 1. If the SDT's intent is that partial loss of a DC Tie should be reported, the SRC recommends that the Threshold for Reporting be revised to read "Loss of a DC Tie Line, between two separate asynchronous systems, loaded at ≥ 500 MW**, or an unexpected, sudden power reduction of 500 MW or more on a DC Tie Line between two separate synchronous systems that is not caused by a fault on the DC tie line, its inverters, or its AC terminal equipment**."	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristina Marriott - Miller Bros. Solar, LLC - 5 - MRO,WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Julie Hall - Entergy - 1,3,6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 1,3,5,6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1,3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Max Ola - Hydro One Networks, Inc. - 1 - NPCC	
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	
Pirouz Honarmand - Independent Electricity System Operator - 2 - NPCC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Quebec (HQ) - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PG&E is not providing any input for Q1.	
Likes 0	
Dislikes 0	
Response	
Stewart Yuen - Nuclear Energy Institute - NA - Not Applicable - NA - Not Applicable	

Answer	
Document Name	
Comment	
NEI has no comment	
Likes 0	
Dislikes 0	
Response	

2. The Standard Drafting Team (SDT) proposes a two (2) year implementation plan for EOP-004-5. Do you agree with the proposed implementation plan? If you do not support the implementation plan as proposed, please explain the changes that, if made, would result in your support.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	No
Document Name	
Comment	
Responsible entities have already developed tracking mechanisms and SCADA requirements for IBRs. As event reports have illustrated, the entities are well aware of aggregated loss of IBRs and negate the need to extend reporting to two years (on top of the timeframe already expired creating this Standard.) A shorter timeframe of no more than six months is appropriate for the activities that are already well established within each responsible entity footprint.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Consideration of expanding the explanation of the threshold established would help FirstEnergy in fully supporting this implementation plan.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

The lack of clarity in which IBRs are to be included in the BA's calculation (see response to Q1) makes it difficult to determine if new telemetry will required to be installed and if it can be done within 2 years. This may be a supply chain issue if multiple entities are sourcing similar equipment for installation.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	No
Document Name	

Comment
SPP recommends that the drafting team include the technical rationale language (shown below) into the Implementation Plan. From our perspective, this will help ensure the prioritization needs of this project aligns appropriately with other impactful projects. "The proposed EOP-004-5 Standard will not move forward to final ballot until the IBR Glossary of Terms is finalized by Project 2020-06".

Likes 0	
Dislikes 0	

Response

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

Comment
Since this proposed change is implicitly tied to NERC projects 2021-04 (PRC-028) and 2023-02 (PRC-030), will the implementation timeline be coordinated between this project and the two projects referenced? The concern is that if the implementation plan does not align with Project 2021-04 and 2023-02's implementation plan, the BA may face some challenges in getting the appropriate data needed to perform further analysis for the event. Likewise, the GOs involved in the generation loss event will also not be able to perform analysis as required under PRC-030 if the appropriate equipment (SER/FR/DDR) has not been installed at the IBR Facilities. AES Clean Energy recommends that the Project 2023-01 drafting team coordinates with the drafting teams from Project 2021-04 and 2023-02 to ensure that either the implementation plans from all three projects are taken into account and aligned or that some exceptions are provided to the GO where data is not readily available when request is made by the BA.

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

Dislikes 0	
Response	
Alison MacKellar - Constellation - 5,6	
Answer	No
Document Name	
Comment	
Constellation supports NAGF comments. Alison Mackellar on behalf of Constellation Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	No
Document Name	
Comment	
Constellation supports NAGF comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

The NAGF is concerned that the timeline specified in proposed implementation plan is not coordinated closely with other active IBR related NERC Projects (Project 2021-04 and Project 2023-02). The current proposed Implementation Plan for Project 2023-01 may lead to inability for the BA to obtain the necessary data from GOs to perform detailed analysis if the timeline between the projects are not aligned with each other.	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
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 supports the EEI comments.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI does not oppose the two (2) year implementation plan as proposed.	
Likes 0	
Dislikes 0	
Response	
Andrew Smith - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

AZPS supports the proposed two (2) year implementation plan.

Likes 0	
Dislikes 0	
Response	
Helen Wang - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Per EEI comments.	
Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Support EEI comments.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNMR supports the two-year implementation pending approval of the IBR and IBR Unit definitions prior to implementation of EOP-004-5.	

Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
MRO NSRF agrees with the proposed implementation plan.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
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	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Quebec (HQ) - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Pirouz Honarmand - Independent Electricity System Operator - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Max Ola - Hydro One Networks, Inc. - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1,3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 1,3,5,6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 1,3,6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristina Marriott - Miller Bros. Solar, LLC - 5 - MRO,WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stewart Yuen - Nuclear Energy Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
NEI has no comment	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PG&E is not providing any input for Q1.	
Likes 0	
Dislikes 0	
Response	

3. The SDT believes the language of EOP-004-5 addresses the issues outlined in the SAR in a cost-effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost-effective approaches, please provide your recommendation and, if appropriate, technical, or procedural justification.

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
The current proposed IBR definition is open-ended and therefore not cost effective.	
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 notes that the proposed IBR aggregate generation threshold >= 500 MW and the associated analysis triggered will lead to inefficient used of limited GO/GOP resources.	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	No
Document Name	
Comment	
When paired with PRC-028, which will require every IBR to install DMEs, EOP-004 reporting will in turn initiate more Events Reports to be submitted by the BAs. Which will initiate many more data requests for IBRs. Kimberly Turco on behalf of Constellation Segments 5 and 6	

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5,6

Answer	No
Document Name	

Comment

When paired with PRC-028, which will require every IBR to install DMEs, EOP-004 reporting will in turn initiate more Events Reports to be submitted by the BAs. Which will initiate many more data requests for IBRs.

Alison Mackellar on behalf of Constellation Segments 5 and 6.

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	

Comment

As stated above, this proposed change is implicitly tied to NERC projects 2021-04 (PRC-028) and 2023-02 (PRC-030) and can indirectly affect Generator Owners. At the moment it is difficult to understand the true cost of implementing these two new Standards and as such it is difficult to say for sure if the issues can be addressed in a cost-effective manner. Coordination between the drafting teams on implementation plans will greatly increase our ability to evaluate the cost-effectiveness of these changes.

Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

Without knowing if or how much new telemetry will be required to be installed, it’s not possible to comment on the cost effectiveness of the solution.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Efforts and timing of this reporting would be based on the threshold which we feel still needs appropriate review by the DT.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment

As noted in MISO’s response to Q1, setting the threshold for IBR generation loss reporting in the Eastern Interconnection at ≥ 500 MW is too low. Not only will this introduce a substantial amount of administrative burden, it may also pull BA resources away from managing real-time reliability issues. To better balance reliability gains against the amount of effort required, MISO proposes an IBR generation loss reporting threshold of ≥ 2,000 MW for the Eastern Interconnection. This aligns with the existing threshold for reporting “Generation loss” events.

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 does not see issues with cost-effectiveness as long as the BA is not required to increase what is already telemetered on its system.

Likes 0	
Dislikes 0	
Response	

Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kristina Marriott - Miller Bros. Solar, LLC - 5 - MRO,WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Julie Hall - Entergy - 1,3,6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Schuldt - Black Hills Corporation - 1,3,5,6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Max Ola - Hydro One Networks, Inc. - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Smith - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Chantal Mazza - Hydro-Quebec (HQ) - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Salt River Project - 1,3,5,6 - WECC	
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	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy’s focus is to assure the effective and efficient reduction of risks to the reliability and security of the grid and will not provide comments on cost effectiveness of the proposed changes.	
Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	
Document Name	
Comment	
No comment.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
No comment.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PG&E is not providing any input for Q1.	
Likes 0	
Dislikes 0	
Response	
Stewart Yuen - Nuclear Energy Institute - NA - Not Applicable - NA - Not Applicable	

Answer	
Document Name	
Comment	
NEI has no comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
WECC will leave commenting on the cost-effectiveness to the applicable entities.	
Likes 0	
Dislikes 0	
Response	

4. Provide any additional comments on the standard and technical rationale for the DT to consider, if desired.

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

Answer	
Document Name	

Comment

The new IBR term (or terms) should be listed within the Standard or referenced to the appropriate SDT (2020-06) to support consistency. As is, if this passes with the footnote is it errata change to remove? What if the definition changes the SDT expectations? Note that the definition finalized may not make a distinction between “BES-connected” and “BPS-connected” IBRs which may require changes in the threshold language.

The SDT should consider removal of the “Generation loss” sentence as the original and updated sentence is not realistic. The generation loss is not “used to report Forced Outages” rather it is a result of Forced Outages. It should be noted that the definition of Forced Outage includes two parts:” 1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure.” which does not necessarily support inclusion of radial transmission facility for IBRs .

Likes 0	
Dislikes 0	

Response

Stewart Yuen - Nuclear Energy Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	03-27-24_NERC_Industry Comments EOP-004.pdf

Comment

The following comments are attached as a PDF with footnotes:

On behalf of the nuclear energy industry, the Nuclear Energy Institute (NEI)1 submits the attached comment in response to the North American Electric Reliability Corporation (NERC) Project 2023-01 EOP-004 IBR Event Reporting. NEI supports NERC’s objective of collecting information from the commercial nuclear power industry to, in part, fulfill its overall national security and Department of Homeland Security’s National Response Framework responsibilities but requests that the Standard Design Team (SDT) coordinate the proposed revisions to EOP-004 with the DOE update to Form DOE-417.

The current expiration date for form DOE-417 is May 31, 2024. DOE posted a Notice and Request for Comment on the three-year extension of DOE-417, with changes, as published in the Federal Register on August 30, 2023.2 NEI therefore requests that the SDT update EOP-004 to align with the changes with the final version of DOE-417 when published to alleviate the need for a future Standard Authorization Request.

Specifically, NEI submitted comments to the DOE on October 30, 2023, requesting that the DOE include an exemption in the DOE-417 Form for commercial nuclear power plants to alleviate a duplicative reporting requirement for commercial power reactors covered by requirements of the Nuclear Regulatory Commission (NRC). On January 8, 2024, NEI received a response from the DOE that the DOE plans to exempt commercial power reactors based on the existing requirements of the NRC for the industry to report physical and cybersecurity incidents and events.

As a matter of background, the NRC requires commercial reactor licensees to protect specific system functions from: cyber attacks that would adversely impact the operation of systems, networks, and associated equipment; adversely impact the integrity or confidentiality of data and/or software; and deny access to systems, services, and/or data.3

Commercial power reactor licensees implement these requirements through a cyber security plan that must be approved by the NRC and is subject to NRC oversight, including inspections and, if necessary, enforcement action.4 These plans lay out comprehensive cyber security programs that include air gapping systems, use of tamper-proof devices, log reviews and additional technical, management, and operational controls, providing significant levels of defense-in-depth. The NRC and the industry have issued detailed regulatory guidance to assist licensees in complying with the NRC's cybersecurity requirements.5 Notably, these documents include NEI 08-09, "Cyber Security Plan for Nuclear Power Reactors," and NRC Regulatory Guide 5.71, "Cyber Security Programs for Nuclear Facilities."6 The NRC's reporting framework, 10 CFR 73.77, "Cyber Security Event Notifications," delineates criteria for 1-hour, 4-hour, and 8-hour notifications to the NRC Headquarters Operations Center (HOC) via the Emergency Notification System (ENS), as well as 24-hour recordable incident/events.

Regarding physical security, following the terrorist attacks of 2001, the NRC issued voluntary guidance for licensees to expeditiously notify the NRC HOC within 15-minutes of an imminent or actual hostile action. All nuclear plant licensees formally responded to the NRC's voluntary guidance, and incorporated the expedited notification to the NRC HOC, which has been in place since 2005. Subsequently, On March 14, 2023, the NRC noticed in the Federal Register a final rule pertaining to security event notifications.7 The final rule codifies the 15-minute notifications to the NRC HOC to facilitate the NRC's prompt notification to other licensees and DHS' National Operations Center.
8 The reporting required under NERC Standard EOP-004 – Attachment 1 and Form DOE-417 duplicates the required 15-minute notification to the NRC HOC under 10 CFR 73.1200(a). Additionally, the NRC's final rule codified reporting requirements regarding suspicious activity incidents and events to the NRC HOC within 4-hours under 10 CFR 73.1215. (This reporting was previously reported voluntarily since 2015). This rule includes reporting of all unauthorized drone and unmanned aerial system/vehicles in the vicinity of all NRC licensed nuclear facilities. The established reporting requirements to the NRC are timelier than those required under NERC Standard EOP-004 – Attachment 1 and Form DOE-417.

Prompt notifications by NRC licensees of a cyber or physical incident/event are vital to the NRC's ability to take immediate action in response and if necessary, notify other government agencies and critical infrastructure facilities. Timely notifications enable the NRC to: 1) inform the U.S. Department of Homeland Security, federal intelligence and law enforcement agencies of incident/events that could endanger public health and safety or impair the common defense and security; (2) provide information to assist in threat-assessment processes; and 3) respond to public or media inquiries.9

In summary, continuing to impose reporting requirements of NERC Standard EOP-004 – Attachment 1 and Form DOE-417 on the commercial nuclear industry duplicates existing requirements of the NRC. Discontinuing such duplicative reporting aligns with the intent of Homeland Security's recommendations to streamline reporting processes and to "avoid conflicting, duplicative, or burdensome requirements."10 Further, NERC should rely on the sectors identified within Presidential Policy Directive 21 (PPD-21), specifically the NRC. PPD 21 states, "The NRC is to collaborate, to the extent possible, with DHS, DOJ, the Department of Energy, the Environmental Protection Agency, and other Federal departments and agencies, as appropriate, on strengthening critical infrastructure security and resilience."11

NEI requests that NERC Standard EOP-004 – Attachment 1 align with the changes to DOE-417 Form for commercial nuclear power plants. This should be coordinated with the NRC to ensure proper alignment between the NERC, DOE and NRC on any changes.

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1 The Nuclear Energy Institute (NEI) is responsible for establishing unified policy on behalf of its members relating to matters affecting the nuclear energy industry, including the regulatory aspects of generic operational and technical issues. NEI's members include entities licensed to operate commercial nuclear power plants in the United States, nuclear plant designers, major architect and engineering firms, fuel cycle facilities, nuclear

materials licensees, and other organizations involved in the nuclear energy industry
2 88 FR 59887

3 10 CFR 73.54(a)(2).
4 The NRC conducts inspections to ensure that operating power reactor licensees are implementing the cyber security programs at their facilities as described in their NRC-approved cyber security plans. See, e.g., NRC Inspection Procedure 71130.10, “Cyber Security.”
5 For example, NRC Regulatory Guide (RG) 5.71, “Cyber Security Programs for Nuclear Facilities,” (January 2010), provides a comprehensive approach to comply with 10 CFR 73.54 for cyber security by using strategies in NIST SP 800-53, Revision 4, “Recommended Security Controls for Federal Information Systems.” RG 5.71 is currently undergoing revision by the NRC. See Draft Regulatory Guide (DG)-5061, “Cyber Security Programs for Nuclear Power Reactors,” (August 2018). NEI has issued NEI 08-09, Revision 6, “Cyber Security Plan for Nuclear Power Reactors,” to further support industry compliance with the relevant NRC requirements.
6 Specifically, RG 5.71 directs licensees to protect against supply chain threats and vulnerability to maintain the integrity of acquired critical digital assets by employing the following measures: (1) establishing trusted distribution paths, (2) validating vendors, and (3) requiring tamper proof products or tamper evident seals on acquired products. Licensees are further directed to perform an analysis for each product acquisition to determine that the product fulfills the security requirements necessary to address the security controls in Appendices B and C to RG 5.71, and to use heterogeneity to mitigate vulnerabilities associated with the use of a single vendor’s product.
7 “Enhanced Weapons, Firearms Background Checks, and Security Event Notifications; Final rule and guidance,” 88 Fed. Reg. 15864 (March 14, 2023).

8 Regulatory Guide 5.62, “Physical Security Event Notifications, Reports, and Records,” Revision 2
9 NEI 15-09, Revision 1, “Cyber Security Event Notification”
10 Homeland Security Office of Strategy, Policy, and Plans Report, “Harmonization of Cyber Incident Reporting to the Federal Government,” September 19, 2023
11 https://obamawhitehouse.archives.gov/the-press-office/2013/02/12/presidential-policy-directive-critical-infrastructure-security-and-resil

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)

Answer	

Document Name

Comment

While the 500 MW threshold is appropriate for EOP-004, the SRC recommends that the SDT coordinate with the NERC Event Analysis program to determine whether additional categories should be created for analysis of discovered IBR generation loss events of less than 500 MW that occur during periods of low wind or solar output and that would have resulted in a loss ≥ 500 MW if IBR output had been higher at the time of the event (such as an event that impacts a large number of units during a period of low per-unit output and would therefore have had a much larger impact on the BES if it had occurred during a period of high per-unit output).

Likes 0

Dislikes 0

Response

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

Answer

Document Name

Comment

Thank you for the opportunity to comment.

Likes 0

Dislikes 0

Response

Israel Perez - Salt River Project - 1,3,5,6 - WECC

Answer

Document Name

Comment

na

Likes 0

Dislikes 0

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer

Document Name	
Comment	

In response to the DOE EIA's Notice and Request for Comments on the three-year extension of Form DOE-417, with changes, published in the Federal Register on 8/30/23, the Nuclear Energy Institute (NEI) submitted comments to the DOE on 10/30/23 requesting that the DOE include an exemption in the Form DOE-417 for commercial nuclear power plants to alleviate a duplicative reporting requirement for commercial power reactors covered by the Nuclear Regulatory Commission (NRC). On 1/8/24, the NEI received a response to comments from the DOE in that the DOE plans to exempt commercial power reactors regulated by the NRC and subject to the physical and cybersecurity event notification requirements of 10 CFR Part 73. This change was evidenced in the DOE EIA's additional Notice and Request for Comments on the three-year extension of Form DOE-417, with changes, published in the Federal Register on 2/21/2024. We request that the drafting team coordinate the changes being proposed in EOP-004-5 with this DOE update to Form DOE-417.

Likes 0	
Dislikes 0	
Response	

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

Answer	
Document Name	
Comment	

1. {C}Section C1.2 Evidence Retention and usage of the term "full-time". In the redline, "full time" has erroneously been corrected to "full-time". In this case, what is being referred to is the entire period since the last audit, i.e the full "time period". It is our understanding that there shouldn't be a hyphen since "full" is the adjective for "period". A suggestion to render the term less ambiguous would be to drop the word "time" and replace with "full period since last audit" instead.

2. Requirement R1 states that each Responsible Entity shall have an event Operating Plan in accordance with Attachment 1 that includes the protocol(s) for reporting to required organizations. However, in the VSL table for R1, only the failure to include an applicable event type is considered. The VSL table should also include failure to notify one of the required organizations.

For example, if the RC has requested of all entities to be copied on all EOP-004 event reports, and thereby be included in the entities' event Operating Plan, failure to do so by an entity in the RC's footprint should be considered a non-compliance and be explicit in the VSL table.

Note that in this situation, if the entity did include the RC in its Operating Plan, but neglected to report an event to the RC, it would be in non-compliance with R2. However, if the entity did not include the RC in its Operating Plan (as requested by the RC), then non-compliance should be with Requirement R1 and the VSL should be clarified to include omission of one or more requesting entities in an event reporting Operating Plan.

Likes 0	
Dislikes 0	

Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	
Document Name	
Comment	
SPP recommends that the drafting team remove the term “GO-IBR” from the technical rationale since that language was removed from the Rules of Procedures (RoP) Appendix 5A by the NERC Board of Trustees (BoT).	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Quebec (HQ) - 1 - NPCC	
Answer	
Document Name	
Comment	
Section C1.2 Evidence Retention and usage of the term “full-time”. In the redline, “full time” has erroneously been corrected to “full-time”. In this case, what is being referred to is the entire period since the last audit, i.e. the full “time period”. It is our understanding that there shouldn’t be a hyphen since “full” is the adjective for “period”. A suggestion to render the term less ambiguous would be to drop the word “time” and replace with “full period since last audit” instead. Requirement R1 states that each Responsible Entity shall have an event Operating Plan in accordance with Attachment 1 that includes the protocol(s) for reporting to required organizations. However, in the VSL table for R1, only the failure to include an applicable event type is considered. The VSL table should also include failure to notify one of the required organizations. For example, if the RC has requested of all entities to be copied on all EOP-004 event reports, and thereby be included in the entities’ event Operating Plan, failure to do so by an entity in the RC’s footprint should be considered a non-compliance and be explicit in the VSL table. Note that in this situation, if the entity did include the RC in its Operating Plan, but neglected to report an event to the RC, it would be in non-compliance with R2. However, if the entity did not include the RC in its Operating Plan (as requested by the RC), then non-compliance should be with Requirement R1 and the VSL should be clarified to include omission of one or more requesting entities in an event reporting Operating Plan.	
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	

Section C1.2 Evidence Retention and usage of the term “full-time”. In the redline, “full time” has erroneously been corrected to “full-time”. In this case, what is being referred to is the entire period since the last audit, i.e. the full “time period”. It is our understanding that there shouldn’t be a hyphen since “full” is the adjective for “period”. A suggestion to render the term less ambiguous would be to drop the word “time” and replace with “full period since last audit” instead.

Requirement R1 states that each Responsible Entity shall have an event Operating Plan in accordance with Attachment 1 that includes the protocol(s) for reporting to required organizations. However, in the VSL table for R1, only the failure to include an applicable event type is considered. The VSL table should also include failure to notify one of the required organizations.

For example, if the RC has requested of all entities to be copied on all EOP-004 event reports, and thereby be included in the entities’ event Operating Plan, failure to do so by an entity in the RC’s footprint should be considered a non-compliance and be explicit in the VSL table.

Note that in this situation, if the entity did include the RC in its Operating Plan, but neglected to report an event to the RC, it would be in non-compliance with R2. However, if the entity did not include the RC in its Operating Plan (as requested by the RC), then non-compliance should be with Requirement R1 and the VSL should be clarified to include omission of one or more requesting entities in an event reporting Operating Plan.

Likes 0	
Dislikes 0	
Response	

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

Answer	
Document Name	
Comment	

Technical Rationale, Section 2: In Section 2, page 3 of the Technical Rationale the Event Type titled “Loss of DC Tie Line” contains a justification for the reporting threshold as follows: “SDT determined the 500 MW threshold from the Event Analysis Process (Category 1j) should remain for consistency.” The Event Analysis Process (voluntary process) and EOP-004 (mandatory process) do not align, and it is unclear why such alignment is necessary since the purpose of EOP-004 and the Event Analysis Process are different. Moreover, we are unaware of any DC tie line events and supporting event analysis reports that have been developed to justify such a change (i.e., elevating a voluntary event report to require mandatory reporting under EOP-004). To address our concern, we ask that consideration be given to expanding the Technical Rationale to more clearly explain and justify why adding this new Event Type is necessary. We further ask that the phrase “should remain for consistency” be removed because it incorrectly implies that this Event Type existed within the previous version of EOP-004, which it did not. To address our concerns, an appropriate technical justification should be added to the Technical Rationale that justifies the addition of this new Event Type to EOP-004-5, or if none can be found please consider removing the “Loss of DC Tie Line” Event Type from EOP-004-5 until a technical justification can be developed.

Likes 0	
Dislikes 0	

Response

Helen Wang - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	
Document Name	

Comment

Per EEI comments

Likes 0	
Dislikes 0	

Response

Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	
Document Name	

Comment

Supporting EEI's comments.

Likes 0	
Dislikes 0	

Response

Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	
Document Name	

Comment

Support EEI comments.

Likes 0	
Dislikes 0	

Response	
Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PG&E requests that the SDT coordinate the proposed revisions to EOP-004 with the DOE update to Form DOE-417. The current expiration date for form DOE-417 is 5/31/24. DOE posted a Notice and Request for Comments on the three-year extension of DOE-417, with changes, as published in the Federal Register on 8/30/23. PG&E, therefore requests that the SDT update EOP-004 to align with the changes with the final version of DOE-417 when published to alleviate the need for a future SAR. Specifically, the Nuclear Energy Institute (NEI) submitted comments to the DOE on 10/30/23 requesting that the DOE include an exemption in the DOE-417 Form for commercial nuclear power plants to alleviate a duplicative reporting requirement for commercial power reactors covered by the Nuclear Regulatory Commission (NRC). On 1/8/24, the NEI received a response to comments from the DOE in that the DOE plans to exempt commercial power reactors regulated by the NRC and subject to the physical and cybersecurity event notification requirements of 10 CFR Part 73.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5,6	
Answer	
Document Name	
Comment	
Constellation requests that the SDT coordinate the proposed revisions to EOP-004 with the DOE update to Form DOE-417. The current expiration date for form DOE-417 is 5/31/24. DOE posted a Notice and Request for Comments on the three-year extension of DOE-417, with changes, as published in the Federal Register on 8/30/23. Constellation therefore requests that the SDT update EOP-004 to align with the changes with the final version of DOE-417 when published to alleviate the need for a future SAR. Specifically, the Nuclear Energy Institute (NEI) submitted comments to the DOE on 10/30/23 requesting that the DOE include an exemption in the DOE-417 Form for commercial nuclear power plants to alleviate a duplicative reporting requirement for commercial power reactors covered by the Nuclear Regulatory Commission (NRC). On 1/8/24, the NEI received a response to comments from the DOE in that the DOE plans to exempt commercial power reactors based on the existing requirements of the NRC for the industry to report physical and cybersecurity incidents/events. Alison Mackellar on behalf of Constellation Segments 5 and 6.	
Likes 0	
Dislikes 0	

Response	
Kimberly Turco - Constellation - 5,6	
Answer	
Document Name	
Comment	
Constellation requests that the SDT coordinate the proposed revisions to EOP-004 with the DOE update to Form DOE-417. The current expiration date for form DOE-417 is 5/31/24. DOE posted a Notice and Request for Comments on the three-year extension of DOE-417, with changes, as published in the Federal Register on 8/30/23. Constellation therefore requests that the SDT update EOP-004 to align with the changes with the final version of DOE-417 when published to alleviate the need for a future SAR. Specifically, the Nuclear Energy Institute (NEI) submitted comments to the DOE on 10/30/23 requesting that the DOE include an exemption in the DOE-417 Form for commercial nuclear power plants to alleviate a duplicative reporting requirement for commercial power reactors covered by the Nuclear Regulatory Commission (NRC). On 1/8/24, the NEI received a response to comments from the DOE in that the DOE plans to exempt commercial power reactors based on the existing requirements of the NRC for the industry to report physical and cybersecurity incidents/events.	
Likes 0	
Dislikes 0	
Response	
Max Ola - Hydro One Networks, Inc. - 1 - NPCC	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
Requirement R2 - The NAGF is concerned that the proposed requirement will not address the data availability issue identified in previous events. As structured, there is no time limit on the BA to determine if a report is needed. This can lead to problems with entity data retention policies that typically	

retain data for a 10-day period. For example, the BA event reporting Operating Plan calls for data to be reviewed weekly (7-day period) to identify a reportable event and then 24hrs or end of the next business day to report the event to NERC (total of 8-9 days). The NERC Event Analysis team would then request data from the generators and the generators would have 1-2 days to respond before the data is overwritten and no longer available. It is unreasonable to assume that the generator owner/operators will be able to gather such data in one day. The BAs must determine a reportable event sooner to allow the GOs/GOPs sufficient time to gather the necessary data prior to the data being overwritten.

Violation Severity Level R2 – The NAGF requests that the proposed VSL language be aligned with R2.

The NAGF also requests that the SDT coordinate the proposed revisions to EOP-004 with the DOE update to Form DOE-417. The current expiration date for form DOE-417 is 5/31/24. DOE posted a Notice and Request for Comments on the three-year extension of DOE-417, with changes, as published in the Federal Register on 8/30/23. The NAGF therefore requests that the SDT update EOP-004 to align with the changes with the final version of DOE-417 when published to alleviate the need for a future SAR.

The NAGF looks forward to working with NERC to ensure the IBR processes across all applicable NERC Standards are coordinated and reasonable as we move forward.

Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
Dislikes 0	

Response

Alan Kloster - Evergy - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the MRO NSRF on question #4

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1,3	
Answer	
Document Name	
Comment	
Exelon requests the project drafting team coordinate the revision to EOP-004 with the DOE to ensure alignment between the final version of EOP-004 and Form DOE-417. Note that the DOE-417 is likely undergoing review at this time, there may be revisions to EOP-004 that are necessary to align with the next revision of the DOE-417.	
Likes 1	Jennie Wike, N/A, Wike Jennie
Dislikes 0	
Response	

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5,6	
Answer	
Document Name	
Comment	
The VSLs for R2 do not appear to have been updated to correctly reflect the latest revisions of the obligation itself. It would seem the phrase “the end of the next business day, as applicable” was deleted but then copied back into the draft in its entirety, rather than perhaps incorporating what had been newly proposed for R2 (for example, the phrase “whichever occurs later”). Please review and correct, as necessary.	
Likes 0	
Dislikes 0	
Response	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	
Comment	
Align the Violation Severity Level wording for R2 with the R2 requirement language for all levels. The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan either by 24 hours after recognition of meeting an event type threshold for reporting or by the end of the next business day, as applicable.	
Likes 0	
Dislikes 0	
Response	