Comment Report

Project Name:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 - Draft 1 - EOP-012-2
Comment Period Start Date:	6/5/2023
Comment Period End Date:	7/20/2023
Associated Ballots:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 EOP-012-2 | Non-Binding Poll IN 1 NB 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 EOP-012-2 IN 1 ST 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 Implementation Plan | EOP-012-2 IN 1 OT

There were 79 sets of responses, including comments from approximately 177 different people from approximately 119 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

See the unofficial comment form for additional information:https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_Unofficial_Comment_Form_Initial%20Ballot%20EOP-012-2_June2023.docx

1. Do you agree that the proposed definition of Generator Cold Weather Constraint provides additional clarity to the requirements on EOP-012-2, is auditable and meets the directive in the FERC Order in the most effective way? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

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2. Do you agree that the proposed Requirement R1 language accounts for the effects of precipitation and the accelerated cooling effect of wind when providing temperature data per Key Recommendation 1c? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

3. Do you agree that the proposed date of October 1, 2027 is an appropriate time frame for units that enter commercial operation after this date to implement the enhanced cold weather requirements that are contained within Requirement R2? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

4. The SDT structured R2.1 and R2.2 in the vein of an if/then statement. The intent being, if a GO implements R2.1, then they would be compliant with Requirement R2. If a GO does not implement R2.1 but implements R2.2, then they would be compliant with Requirement R2. Stated differently, a GO would only risk non-compliance with Requirement R2 if they did neither R2.1 nor R2.2. Does the proposed language, as drafted by the SDT, provide that clarity and reflect the SDT's intent as stated above? If not, please provide suggested clarifying language.

5. The SDT proposes two timeframes, 24 months for addressing existing equipment or freeze protection and 48 months for implementing new equipment or freeze protection, for Corrective Action Plans in Requirement R7. Do you agree that the timeframes proposed are appropriate? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

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6. Do you agree that Requirement R8 is sufficient to inform the Balancing Authority of the potential impacts a constraint declaration may have on the generating unit's performance to its Extreme Cold Weather Temperature? If you do not agree, or if you do agree but have an alternative approach that will more effectively address the concern, please provide your recommendation and, if appropriate, technical or procedural justification.

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7. Per the FERC directive to shorten the timeframe to implement freeze protection measures on existing units, the SDT proposes an implementation plan where all requirements of EOP-012-2 go into effect on the effective date of the standard except Requirement R3 which has a 12-month implementation time frame. The chart below is included to compare the EOP-012-1 and EOP-012-2 IPs for this requirement

which requires GOs to have the capability to operate at the ECWT or a CAP written by the effective date of the requirement. If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

8. The SDT proposes that the modifications in EOP-012-2 meet the key recommendations in The Report as well as the directives in the FERC order 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.

9. Provide any additional comments for the standard drafting team to consider, including the provided technical rationale document, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
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
Santee Cooper	Don Cribb	5		Santee Cooper	Paul Camilletti	Santee Cooper	1,3,5,6	SERC
					Mark Taylor	Santee Cooper	1,3,5,6	SERC
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					John Nierenberg	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	RF
					Jennifer Bray	Arizona Electric Power Cooperative, Inc.	1	WECC
					Sara Orr	Golden Spread Electric Cooperative, Inc.	5	Texas RE

					Chris Adams	East Kentucky Power Cooperative	3	SERC
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Nick Fogleman	Prairie Power, Inc.	1	SERC
					Austin Towne	Western Farmers Electric Cooperative	1,5	MRO
MRO	Jou Yang	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Chris Bills	City of Independence, Power and Light Department	5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bryan Sherrow	Board of Public Utilities	1	MRO
					Terry Harbour	Berkshire Hathaway Energy - MidAmerican Energy Co.	1	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO

						Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
						Michael Brytowski	Great River Energy	1,3,5,6	MRO
						Shonda McCain	Omaha Public Power District	6	MRO
						George E Brown	Pattern Operators LP	5	MRO
						George Brown	Acciona Energy USA	5	MRO
						Jaimin Patel	Saskatchewan Power Cooperation	1	MRO
						Kimberly Bentley	Western Area Power Administration	1,6	MRO
						Jay Sethi	Manitoba Hydro	1,3,5,6	MRO
						Michael Ayotte	ITC Holdings	1	MRO
Entergy	Julie Hall	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)	Bobbi Welch	Midcontinent ISO, Inc.	2	NA - Not Applicable
						Darcy O'Connell	California ISO	2	WECC
						Gregory Campoli	New York Independent System Operator	2	NPCC
						Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC
						John Pearson	ISO New England, Inc.	2	NPCC
						Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
						Matthew Harward	Southwest Power Pool, Inc. (RTO)	2	NA - Not Applicable

					Thomas Foster	PJM Interconnection, L.L.C.	2	RF
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Michael Johnson	Michael Johnson		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
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Patricia Robertson	Patricia Robertson		WECC	BC Hydro Balloters	Adrian Andreoiu	BC Hydro and Power Authority	1	WECC

					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Hootan Jarollahi	BC Hydro and Power Authority	3	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
					John Hastings	National Grid	1	NPCC
					Michael Jones	National Grid USA	1	NPCC
					Joshua London	Eversource Energy	1	NPCC
Ryan Strom	Ryan Strom		RF	Buckeye Power Group	Carl Spaetzel	Buckeye Power, Inc.	3	RF
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Kevin Zemanek	Buckeye Power, Inc.	5	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

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1. Do you agree that the proposed definition of Generator Cold Weather Constraint provides additional clarity to the requirements on EOP-012-2, is auditable and meets the directive in the FERC Order in the most effective way? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

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

Answer	No
Document Name	

Comment

Tacoma Power agrees that the SDT's approach to create definitions of technical, commercial and operational constraints addresses the FERC Order criteria. However, Tacoma Power does not agree that the proposed definitions are clear and auditable. Additional clarification is needed for entities to understand the scope of what's included in these constraints.

For example, the "surrounding environment" in the Operational Constraint definition can be interpreted in different ways. Does the SDT mean "surrounding environment" to include EPA emission limits, FERC limits on water levels, or agreements with local tribal authorities? Tacoma Power recommends adding environmental examples for the Operational Constraint criteria in the Technical Rationale, as follows: "*Operational Constraints: limited fuel supply, voided warranties, required outage time to implement, reduction in summer capability,* ***EPA emission limits, FERC water level limits, agreements with local authorities,*** *etc.*"

Tacoma Power is concerned that the Technical Constraints definition is creating a situation where an Entity and an auditor will disagree as to who determines whether there are technology solutions that exist. Tacoma Power recommends that the definition should be modified to state "*...as determined by the applicable Entity*" to ensure it's clear that the responsibility is with the Entity to determine the technology solutions.

Likes 2	Luminant - Luminant Energy, 6, Ferrell Russell; Platte River Power Authority, 3, Kiess Richard
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

AEP agrees in principle with the overall direction of the SDT in Phase II of Project 2021-07, and offers the following comments and feedback for consideration.

AEP does not believe that the definition of Commercial Constraint is clear. It is our understanding that it is not the SDT's intent to require that significant expense be invested in units with a limited remaining life, however the team has also stated that they might still want "less significant investments" made as a result of a Cold Weather Event. Without a clear definition, it might appear that some in industry are choosing economics over reliability, even if that is not actually the case. While AEP agrees with the intent of the constraint and the spirit in which it was drafted, we do not believe the language of the constraint and definition currently articulates their intent.

AEP recommends that the definition of Commercial Constraint be revised as follows: “A commercial constraint exists when implementation of selected freeze protection measure(s) are uneconomical to the extent that they would require unreasonably expensive modifications, significant expenditures on equipment with minimal remaining life, or significant expenditures to change the equipment’s original design basis to meet the requirements.”

AEP also provides the following questions and scenarios for consideration.

* Does the phrase “… generating unit not operating...” mean the unit will be retired or the unit is not selected to participate in the market due to the unit’s operating cost?

* Regarding the phrase “…into service at the time of evaluation.” Is this when the freeze protection measure(s) are being evaluated for implementation, or instead, is it when a unit is committing to participate in the day ahead market?

* In the situation where a unit is within a few years of retirement and it has a cold weather event requiring a significant investment, does the GO have the ability to make a declaration to not invest the dollars in that unit? Either way, the present language does not provide this clarity.

* The phrase “limit its operation” within the definition of Operational Constraint is not clear, and renders the definition ineffective. Does the phrase perhaps infer a limitation of generation output?

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3

Answer	No
Document Name	

Comment

There should also be some allowance for processes or procedures to mitigate constraints that allow a generating owner or operator to not install or implement protection measures in areas where historically they have not been needed. For instance water can freeze in a cooling tower basin but the process requires constant circulation of water or constant flow of water in the basn as the mitigating option. As we read the standard we would be required to put heaters or enclosures on the cooling tower basin to eliminate all possible chance of water to freeze within the basin. However this would be unrealistic and would not allow the cooling tower basin, pumps, etc to work as intended.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

Technical Constraint declarations would be subject to opinions as to what is proven versus unproven. There is a no objective, auditable means of making decisions in this respect, and conservatism requires accommodating the outlook of the equipment owners. They should not have to subject their very expensive, very important generation units to retrofits of an experimental nature.

The only way to prove a Commercial Constraint would be a financial study that shows the cost is greater than the market can bear. To do such a study, there are many inputs that would be arguable. NERC auditors do not have the information necessary to pass judgment in this respect.

NERC says moreover in its Rules of Procedure, part 3 of sect. 302 (Essential Attributes for Technically Excellent Reliability Standards), "Each Reliability Standard shall state one or more performance Requirements, which if achieved by the applicable entities, will provide for a reliable Bulk Power System, consistent with good utility practices and the public interest. Each Requirement is not a 'lowest common denominator' compromise, but instead achieves an objective that is the best approach for Bulk Power System reliability, taking account of the ***costs and benefits*** [emphasis added] of implementing the proposal." It is unreasonable to demand that retrofits be applied unless they are so overwhelmingly expensive that they drive the GO out of business. This is not a cost-benefit analysis.

The entire thrust of EOP-012 on this subject is inappropriate. Existing units were built in accordance with all rules and regulations, including those of NERC and ISOs, who were fully aware of the importance of wintertime reliability. GOs should not be expected to now retrofit or re-engineer the units to meet the expectation to perform to a new level without the regulators being willing to pay for these upgrades.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

There should also be some allowance for processes or procedures to mitigate constraints that allow a generating owner or operator to not install or implement protection measures in areas where historically they have not been needed. For instance water can freeze in a cooling tower basin but the process requires constant circulation of water or constant flow of water in the basn as the mitigating option. As we read the standard we would be required to put heaters or enclosures on the cooling tower basin to eliminate all possible chance of water to freeze within the basin. However this would be unrealistic and would not allow the cooling tower basin, pumps, etc to work as intended.

Key Recommendation 1c: To revise EOP-011-2, R7.3.2 to require Generator Owners to account for the effects of precipitation and the accelerated cooling effect of wind when providing temperature data.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	No
Document Name	
Comment	

PGAE agrees and supports the NAGF comments.

Likes 0	
Dislikes 0	
Response	

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	
Comment	

MRO NSRF agrees that the SDT's approach to create definitions of technical, commercial and operational constraints addresses the FERC Order criteria. However, MRO NSRF does not agree that the proposed definitions are clear and auditable. Additional clarification is needed for entities to understand the scope of what's included in these constraints.

For example, the "surrounding environment" in the Operational Constraint definition can be interpreted in different ways. Does the SDT mean "surrounding environment" to include EPA emission limits, FERC limits on water levels, or agreements with local tribal authorities? MRO NSRF recommends adding environmental examples for the Operational Constraint criteria in the Technical Rationale, as follows: "*Operational Constraints: limited fuel supply, voided warranties, required outage time to implement, reduction in summer capability,* ***EPA emission limits, FERC water level limits, agreements with local authorities,*** *etc."*

MRO NSRF is concerned that the Technical Constraints definition is creating a situation where an Entity and an auditor will disagree as to who determines whether there are technology solutions that exist. MRO NSRF recommends that the definition should be modified to state "*...as determined by the applicable Entity*" to ensure it's clear that the responsibility is with the Entity to determine the technology solutions.

Similarly, MRO NSRF is concerned about the auditability of Commercial Constraints. Including language as recommended above, *"...as determined by the applicable Entity",* would help to alleviate these concerns.

Likes 0	
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1

Answer	No
Document Name	
Comment	

The proposed language is focused too much on Thermal Generation, and doesn't consider Hydro facilities that are designed to operate in cold weather. Small hydro entities which are designed to operate in cold weather will have a compliance responsibility that will become administrative risks to this standard. This will raise the risk of non-compliance for these entities, even though reliability will not be enhanced.

Likes 1	Hydro-Quebec (HQ), 1, Turcotte Nicolas
Dislikes 0	
Response	

Daniel Roethemeyer - Vistra Energy - 5

Answer	No
Document Name	
Comment	

We agree with the NAGF comments

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	No
Document Name	
Comment	

SMUD and BANC agree with the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	
Response	

Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	

Although the definitions of the various constraints offer increased clarity on inclusion criteria, these are still problematic. The Technical constraint would be subject to opinions as to what is proven versus unproven and appears to be exclusive to OEM type making it problematic and restrictive. As far as the commercial constraint is concerned, this would require considerable financial study that would be based upon the individual company's business model. This will differ from company to company depending upon financial risk matters as well as change with industry economic trends. NRG does not believe that the constraints can be objectively audited- auditors are not financial experts. NRG offers this suggestion that a standardized process instituted to evaluate criteria (based upon certain parameters) and accepted prior to implementation to prevent inequality in evaluation. Overall these constraints should be defined clearer and examples provided as to what would be acceptable.

Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	

Although the definitions of the various constraints offer increased clarity on inclusion criteria, these are still problematic. The Technical constraint would be subject to opinions as to what is proven versus unproven and appears to be exclusive to OEM type making it problematic and restrictive. As far as the commercial constraint is concerned, this would require considerable financial study that would be based upon the individual company's business model. This will differ from company to company depending upon financial risk matters as well as change with industry economic trends. NRG does not believe that the constraints can be objectively audited- auditors are not financial experts. NRG offers this suggestion that a standardized process instituted to evaluate criteria (based upon certain parameters) and accepted prior to implementation to prevent inequality in evaluation. Overall these constraints should be defined clearer and examples provided as to what would be acceptable.

Likes 0	
Dislikes 0	
Response	

Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No
Document Name	
Comment	

Buckeye supports the comments of ACES:

We appreciate the effort that the SDT put into drafting the objective Generator Cold Weather Constraint criteria as directed by FERC. However, it is our opinion that the proposed definition still contains a bit of ambiguity that needs to be addressed.
Consider the proposed definition of a Technical Constraint. The last sentence states: “Technical constraints include technologies that have not been demonstrated for a sufficient period of time in like assets in the BES.” How is the GO to know how long a technology must be “demonstrated” in order for the timeframe to be considered “sufficient”?
Lastly, while the definition of Commercial Constraint is not ambiguous, it does set a very high bar. We appreciate that this is a difficult term to clearly define; however, under the currently proposed definition, the GO could potentially incur a significant financial impact without reaching the threshold that would preclude the generating unit from operating.

Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NV Energy agrees that the SDT’s approach to create definitions of technical, commercial and operational constraints addresses the FERC Order criteria. However, NV Energy does not agree that the proposed definitions are clear and auditable. Additional clarification is needed for entities to understand the scope of what’s included in these constraints.

For example, the “surrounding environment” in the Operational Constraint definition can be interpreted in different ways. Does the SDT mean “surrounding environment” to include EPA emission limits, FERC limits on water levels, or agreements with local tribal authorities? NV Energy recommends adding environmental examples for the Operational Constraint criteria in the Technical Rationale, as follows: “Operational Constraints: limited fuel supply, voided warranties, required outage time to implement, reduction in summer capability, EPA emission limits, FERC water level limits, agreements with local authorities, etc.”

NV Energy is concerned that the Technical Constraints definition is creating a situation where an Entity and an auditor will disagree as to who determines whether there are technology solutions that exist. NV Energy recommends that the definition should be modified to state “...as determined by the applicable Entity” to ensure it’s clear that the responsibility is with the Entity to determine the technology solutions.

Similarly, NV Energy is concerned about the auditability of Commercial Constraints. Including language as recommended above, “...as determined by the applicable Entity”, would help to alleviate these concerns.

Likes 0	
Dislikes 0	

Response	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
ISO-NE supports the SRC comments. Additionally, ISO-NE would support the removal of "Commercial Constraint" from the definition of Generator Cold Weather Constraint and if a Generator desired to declare a commercial constraint due to cost or economics, they should utilize the proper filing process for relief as outlined in the NERC Rules of Procedure. This would be consistent with the filing process utilized for the IROL-CIP required upgrades.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer	
Answer	No
Document Name	
Comment	
Minnesota Power supports the North American Generator Forum's (NAGF) comments.	
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 definition of Generator Cold Weather Constraint. We agree that the proposed definition does provide more clarity. However, the NAGF questions the auditability of the language used in the commercial and technical constraints.	

The language used under a Technical Constraint would be subject to opinions as to what is proven versus unproven. The NAGF recommends that GOs should not have to install any cold weather reliability technologies other than those offered by the generation unit OEM or certified by them to ensure no warrantee related issues. GOs could otherwise be required to subject their generation units to retrofits of an experimental nature.

It would appear that the only way to prove a Commercial Constraint would be to develop a financial study that determines the cost of freeze protection upgrades is greater than the market can bear. To do such a study, there are many proprietary inputs needed that would be subject to review/audit, depending on who is performing the study. NERC auditors do not have the expertise necessary to opine on the validity of such a study, nor do they have information available to them to question such a study.

NERC states in its Rules of Procedure, part 3 of sect. 302 (Essential Attributes for Technically Excellent Reliability Standards), "Each Reliability Standard shall state one or more performance Requirements, which if achieved by the applicable entities, will provide for a reliable Bulk Power System, consistent with good utility practices and the public interest. Each Requirement is not a 'lowest common denominator' compromise, but instead achieves an objective that is the best approach for Bulk Power System reliability, taking account of the ***costs and benefits*** [emphasis added] of implementing the proposal." The NAGF believes that it is unreasonable to demand that retrofits be applied unless they are so overwhelmingly expensive that they drive the GO out of business. Existing units were built in accordance with all rules and regulations, including those of NERC and ISOs, who were fully aware of the importance of wintertime reliability. GOs should not be expected to now retrofit or re-engineer the units to meet the expectation to perform to a new level without a cost recovery mechanism in place to pay for these upgrades.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	No
Document Name	

Comment

The Commercial Constraint provision is so narrowly written that it fails to allow for any cost-benefit analysis. It appears that the only possible Commercial Constraint would be the cost of compliance being greater than the cost of retiring the generation unit. Invenergy suggests a less restrictive Commercial Constraint—not one that would incentivize the avoidance of making a capital improvement—but one that allows for a reasonable cost-benefit analysis of whether the benefit that would result from a prohibitively priced piece of equipment otherwise necessary for compliance is not worth the cost. The current Commercial Constraint provision is clearly unreasonable. For example, if equipment would improve performance during freezing temperatures by only one (1) degree to be compliant, the GO would have to purchase and install such equipment regardless of its cost, so long as the cost is less than retirement of the unit.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment	
Ameren agrees with and supports NAGF comments on this question.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
Enel North America Inc. would like to thank the Standard Drafting Team for its continued efforts on these Cold Weather Reliability Standards. Enel does not agree that the proposed definition of Generator Cold Weather Constraint is auditable because the Technical, Commercial, and Operational Constraint areas currently introduce a wide array of interpretations. For example, within a Technical Constraint it is stated “Technical constraints include technologies that have not been demonstrated for a sufficient period of time in like assets in the BES.” A ‘sufficient period of time’ may vary among individual Generator Owners based on the level of risk each is willing to accept from a new technology. Therefore, Enel recommends an amendment to the Generator Cold Weather Constraint(s) definition to explicitly state the Generator Owner should determine the criteria in which the constraint(s) would be applied.	
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 appreciate the effort that the SDT put into drafting the objective Generator Cold Weather Constraint criteria as directed by FERC. However, it is our opinion that the proposed definition still contains a bit of ambiguity that needs to be addressed. Consider the proposed definition of a Technical Constraint. The last sentence states: “Technical constraints include technologies that have not been demonstrated for a sufficient period of time in like assets in the BES.” How is the GO to know how long a technology must be “demonstrated” in order for the timeframe to be considered “sufficient”?	

Lastly, while the definition of Commercial Constraint is not ambiguous, it does set a very high bar. We appreciate that this is a difficult term to clearly define; however, under the currently proposed definition, the GO could potentially incur a significant financial impact without reaching the threshold that would preclude the generating unit from operating.

Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	No
Document Name	
Comment	
The Commercial Constraint provision is so narrowly written that it fails to allow for any cost-benefit analysis. It appears that the only possible Commercial Constraint would be the cost of compliance being greater than the cost of retiring the generation unit. Invenergy suggests a less restrictive Commercial Constraint—not one that would incentivize the avoidance of making a capital improvement—but one that allows for a reasonable cost-benefit analysis of whether the benefit that would result from a prohibitively priced piece of equipment otherwise necessary for compliance is not worth the cost. The current Commercial Constraint provision is clearly unreasonable. For example, if equipment would improve performance during freezing temperatures by only one (1) degree to be compliant, the GO would have to purchase and install such equipment regardless of its cost, so long as the cost is less than retirement of the unit.	
Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
The metric for uneconomical in commercial constraint should be more specific	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	

Answer	No
Document Name	

Comment

While AES CE agrees that additional clarity is provided in the proposed definition of Generator Cold Weather Constraints, we believe that the definition would still be subject to opinions. As mentioned in the Technical Rationale, the definition is provided in such a way that it leaves room for interpretation. This would present an extensive effort by entities to document a constraint to avoid subjective interpretation by audit teams. We recommend that the SDT develops an implementation guidance or a CMEP Practice Guide in parallel with EOP-012-2 effort to ensure consistent practices by audit teams across all regions in the interpretation of Generator Cold Weather Constraint.

Additionally, AES CE found the capitalized term "Generator Cold Weather Components" listed in the definition of Generator Cold Weather Constraint(s). Currently, we don't see a definition for "Generator Cold Weather Components". AES CE is seeking clarification from the Standard Drafting Team on whether this is a new term or an error.

Likes 0	
Dislikes 0	

Response

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	No
Document Name	

Comment

Southern Indiana Gas & Electric, Company (SIGE) supports the development of the Generator Cold Weather Constraints definition; however, SIGE believes additional clarity is needed. SIGE recommends modifying the Constraints definition to include the statement: "as determined by the applicable Entity" to clarify that the Entity is responsible for determining the technical solution, economic impact, and/or operational impact.

Additionally, the term, "surrounding environment" is not entirely clear – please provide clarification.

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, 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

SRP agrees and supports NV Energy, AEP, and Tacoma Power comments.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	No
Document Name	

Comment

While the ISO/RTO Council (IRC) Standards Review Committee (SRC)[1] agrees that the proposed definition provides some additional clarity and auditability, the SRC urges consideration of the specific revisions proposed below that would better meet the directive in the FERC order and result in a clearer, more auditable Reliability Standard.

Commercial Constraints – The existing definition of a commercial constraint is overly broad and could lead to the exception swallowing the standard itself. As proposed, a commercial constraint would exist only if it "would result in a generating unit not operating or not being put into service at the time of the evaluation." It is unclear whether "not operating" is intended to refer to a long-term condition (such as mothballing or retirement) or a short-term condition, such as a decision not to offer a unit on a particular operating day. This definition is extremely elusive as to what would be the reason for the unit 'not operating' and consequently raises a host of compliance challenges.

Effectively, the commercial constraint definition would allow a unit owner to claim that a particular winterization task would, in its view, render the unit uneconomical to operate. However, this ability of a unit owner to effectively self-certify that installation of weatherization measures would be uneconomic would provide little in the way of consistency among unit owners and could allow resource owners to prioritize competitive concerns over reliability. Additionally, compliance constraint declarations should be auditable, but auditing a commercial constraint declaration under the current definition would require NERC and the Regions to effectively become economic regulators reviewing and auditing determinations of future market prices, underlying projections of future costs and returns, and a host of related economic analyses. This type of financial and economic auditing and regulation is not part of the appropriate role for NERC or the regional entities.

After engaging in lengthy internal discussions regarding the breadth and subjectivity of the commercial exemption, the SRC has come to the conclusion that the most reasonable way to prevent the commercial constraint exemption from swallowing the standard is to revise the definition such that a GO can only claim a commercial constraint for a resource if it has announced plans to retire that unit. Although retirement decisions can be reversed, a public notification of plans to retire a unit would allow an audit team to confirm the commercial impact to the unit without having to review and audit the underlying economic analyses that the resource owner performed. Such public notices also represent defined notifications that prompt system planners to develop alternatives to the continued operation of the unit. In those instances, little would be accomplished by requiring a unit with an announced imminent retirement date to invest in costly winterization upgrades.

For the above reasons, including the compliance challenges associated with such an open-ended commercial constraint exemption, the SRC urges consideration of this more limited definition of a commercial constraint.

Operational Constraints – To provide additional clarity and auditability, the SRC recommends that "would **cause** the generating unit to limit its operations . . ." be replaced with "would **require** the generating unit to limit its operations . . ." in the definition of an operational constraint. The SRC also recommends that the reference to "the surrounding environment" be removed from the definition of an operational constraint and that language be added specifying that an operational constraint exists "if implementation of selected freeze protection measure(s) would cause a violation of an environmental permit that cannot otherwise be mitigated." This would result in a clearer, more auditable definition of *operational constraint*.

[1] For purposes of these comments, the IRC SRC includes CAISO, ERCOT, IESO, ISO-NE, PJM, MISO, NYISO, and SPP.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	No
Document Name	

Comment

Black Hills Corporation agrees and supports the various entities comments, as well as those supplied by NAGF.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	No
Document Name	

Comment

Black Hills Corporation agrees and supports the various entities comments, as well as those supplied by NAGF.

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 5

Answer	No

Document Name	
Comment	

Black Hills Corporation agrees and supports the various entities comments, as well as those supplied by the NAGF.

Likes 0	
Dislikes 0	
Response	

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt

Answer	No
Document Name	
Comment	

Black Hills Corporation agrees and supports the various entities comments, as well as those supplied by NAGF.

Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

The proposed definition for a "Generator Cold Weather Constraint(s)" contains another capitalized term – Generator Cold Weather Component. Shouldn't this be "Generator Cold Weather Critical Component"?

The first sentence under the 'Technical Constraint' sub-bullet is unclear. We suggest the circumstances representing a technical constraint be numbered or bulletized to better distinguish them. For example,

"*A technical constraint exists when **1)** there is no known technical solution for addressing the issue, or **2)** implementation of selected freeze protection measure(s) requires application of new technologies or existing technologies in new applications that would facilitate operations outside of the existing equipment specifications.*"

The description in the 'Operational Constraint' sub-bullet needs further clarity. Is an operational constraint identified ahead of time (as part of Corrective Action Plan development) or in near Real-time during Corrective Action Plan implementation? We offer the following edits for the drafting team to consider if it's an improvement:

"Operational Constraint – An operational constraint exists when implementation of selected freeze protection measure(s) would cause the ***for a*** *generating unit* ***during Real-time operations is expected*** *to limit its operations in order to protect* ***jeopardize*** *either the reliability of the BES, the generating unit itself, the surrounding environment, or personnel* ***safety****."*

Would an operational constraint declaration related to reliability of the BES require supporting concurrence from either the Balancing Authority, Transmission Operator, or Reliability Coordinator?

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	No
Document Name	

Comment

There should also be some allowance for processes or procedures to mitigate constraints that allow a generating owner or operator to not install or implement protection measures in areas where historically they have not been needed. For instance water can freeze in a cooling tower basin but the process requires constant circulation of water or constant flow of water in the basn as the mitigating option. As we read the standard we would be required to put heaters or enclosures on the cooling tower basin to eliminate all possible chance of water to freeze within the basin. However this would be unrealistic and would not allow the cooling tower basin, pumps, etc to work as intended.

Key Recommendation 1c: To revise EOP-011-2, R7.3.2 to require Generator Owners to account for the effects of precipitation and the accelerated cooling effect of wind when providing temperature data.

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 appreciate the effort that the SDT put into drafting the objective Generator Cold Weather Constraint criteria as directed by FERC. However, it is our opinion that the proposed definition still contains a bit of ambiguity that needs to be addressed.

Consider the proposed definition of a Technical Constraint. The last sentence states: "Technical constraints include technologies that have not been demonstrated for a sufficient period of time in like assets in the BES." How is the GO to know how long a technology must be "demonstrated" in order for the timeframe to be considered "sufficient"?

Lastly, while the definition of Commercial Constraint is not ambiguous, it does set a very high bar. We appreciate that this is a difficult term to clearly define; however, under the currently proposed definition, the GO could potentially incur a significant financial impact without reaching the threshold that would preclude the generating unit from operating.	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	No
Document Name	NAGF EOP-012-2 Comment Form Draft 3.docx
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 3, 1; - Patricia Robertson, Group Name BC Hydro Balloters	
Answer	Yes
Document Name	
Comment	
The Generator Cold Weather Constraint(s) definition references Generator Cold Weather Components. Should the reference be Generator Cold Weather Critical Components as that is a defined term?	

Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Key Recommendation 1c: To revise EOP-011-2, R7.3.2 to require Generator Owners to account for the effects of precipitation and the accelerated cooling effect of wind when providing temperature data.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG agrees with NPCC/RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports EEIs comments.	
Likes 0	
Dislikes 0	

Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company agrees with the proposed definition of Generator Cold Weather Constraint.	
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	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS supports the proposed definition Generator Cold Weather Constraint.	
Likes 0	
Dislikes 0	
Response	

Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM supports the proposed definition of Generator Cold Weather Constraint.	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	Yes

Document Name	
Comment	

Constellation agrees that individual Constraint wording adds clarity. Suggest changing introductory wording to add "one or more" constraints, i.e., "... must fall under one or more of..."

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	

Constellation agrees that individual Constraint wording adds clarity. Suggest changing introductory wording to add "one or more" constraints, i.e., "... must fall under one or more of..."

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Hankins - Laura Hankins On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - Laura Hankins	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
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 Standifur - Austin Energy - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Abbas Munir - Bruce Power - 5 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lovita Griffin - Austin Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Imane Mrini - Austin Energy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 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	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Joseph Gatten On Behalf of: Nicholas Friebel, Xcel Energy, Inc., 5, 3, 1; - Joseph Gatten	
Answer	
Document Name	
Comment	
Xcel Energy believes that improvements to the Generator Cold Weather Constraint definition should be made to provide additional clarity. Please refer to EEI comments in response to question 9 of the comment form.	

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE recommends using the proposed term “Generator Cold Weather *Critical* Component” in the definition to ensure clarity and consistency.

Texas RE is concerned the Technical Constraint description could include any current unit needing updates to run reliably. “New technologies” is not defined and subject to interpretation. The description also does not specify what a “sufficient period of time” is.

Texas RE is concerned the proposed ‘Commercial Constraint’ definition is subject interpretation and could lead to difficulties assessing compliance. Clarification is needed in the phrase “at the time of the evaluation”. It is not clear whether this includes the timeframe picked by the entity to implement the freeze protection plans or indicates that the entities will evaluate whether it is economical for the entities to implement the freeze protection measures to operate at the time of Extreme Cold Weather Temperature conditions. Texas RE recommends the drafting team consider the evidence required to demonstrate a Commercial Constraint.

Likes 0	
Dislikes 0	

Response

See the unofficial comment form for additional information: https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_Unofficial_Comment_Form_Initial%20Ballot%20EOP-012-2_June2023.docx

2. Do you agree that the proposed Requirement R1 language accounts for the effects of precipitation and the accelerated cooling effect of wind when providing temperature data per Key Recommendation 1c? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Mike Magruder - Avista - Avista Corporation - 1

Answer	No
Document Name	

Comment

This is simply requiring us to perform a wind chill calculation with an ambiguous 20mph wind speed. Why are we not basing this on the calculations we have available from the ASOS or NWS data that we have already had to complie under EOP 012-1? Some regions or facilities are more protected from wind effects than others, and there is no direct correlation between extreme cold weather tempeartures and wind. So why are we trying to model something that has no technical basis?

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

We agree that “concurrent wind speed and precipitation” language has been incorporated into Requirement R1, Part 1.2.2. Less clear is to whom this information will be provided, and how it will be used by the recipient(s). Some generating technologies / plant designs may be more susceptible to the effects of wind and precipitation than others, but all will be required to address it? The technical rationale document states that “…if the historical minimum temperature occurred at low wind and dry conditions, and actual cold weather event expected conditions are high winds with precipitation, planning personnel will recognize that a specific unit may not achieve the minimum temperature and can arrange for additional resources” or that “…if a calculated design minimum temperature assumes some level of wind and precipitation and actual cold weather expectations are for low wind and dry conditions, planning personnel will recognize that there is increased likelihood that a generation resource may continue to be available below its minimum temperature”. What “planning personnel” are being referred to, and is there a corresponding requirement to provide this information to the planning personnel?

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees and supports the various entities comments, as well as those supplied by the NAGF.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees and supports the various entities comments, as well as those suppied by the NAGF.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees and supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No

Document Name	
Comment	

Black Hills Corporation agrees and supports the various entities comments, as well as those supplied by NAGF.

Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

The SRC agrees that the language in proposed Requirement R1 requires GOs to gather historical data regarding precipitation and wind speed, if available. However, it is unclear how this data is to be used beyond being included in the cold weather preparedness plan under Requirement R4. The SRC recommends that Requirement R4, Part 4.4 be revised to make the implementation of measures to address the effects of precipitation and the cooling effect of the wind mandatory if the data is available, rather than permissive. In addition, the SRC recommends that Requirement R1 be revised to require GOs to gather wind speed and precipitation data at their generating unit locations for use in future analysis if the data is not already being collected by the GO or by a third party from which the GO can procure the data.

Likes 0	
Dislikes 0	
Response	

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	
Comment	

While we agree that the effects of wind and precipitation play an important role in the performance of wind or solar generation during cold weather, these effects are already baked into the capacity factors submitted to the BAs. Additionally, the BAs should have the necessary requirements to perform imminent winter storm impact analysis based on their wide-area situational awareness with the mix of generation types they have in their areas.

Likes 0	
Dislikes 0	
Response	

Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
Enel North America Inc. supports the NAGF's comments and suggests the SDT consider their recommendations.	
Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports NAGF comments on this question.	
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 that the proposed Requirement R1 accounts for the effects of precipitation and wind. In R1, the only place wind and precipitation are mentioned is under 1.2.2, which is focused on design information, actual operating information and under an engineering analysis. R1.2.2 does not account for the wind and precipitation, it only includes what occurred historically or at a single point in the design criteria. These issues are also concerning when paired with what the standard seems to mean by the term freezing. It appears that the SDT means to include three separate issues within the undefined term "freezing" which makes the full extent of the requirements unclear without properly defining what is expected. As currently understood, it appears that the SDT is including actual freezing (water turning to ice), malfunctions cause by fluids becoming too viscous (technically this is congealing, not freezing, but it's functionally equivalent) and accretion/accumulation of moisture (such as blade icing on a wind turbine, snow accumulation on solar panels or ice accumulating on the air inlets of a gas turbine) which is not a form of freezing. If this is the intent, the SDT needs to define the term "freezing" so that all parties are clear on what is covered in the standard.	

The multiple possible impacts of a winter storm cannot be combined into a single point. Impacts will vary greatly based on the mix of temperature, wind speed or precipitation rate. We also point out that wind turbines blades are much more likely to ice when the temperature is near freezing and precipitation occurs rather than at much lower temperatures.

As wind speeds increase the heat transfer rises, although not at a linear rate. So, a unit designed to operate at zero degrees with a 20 mile an hour wind might fail at five degrees with a 40 mile an hour wind. But the proposed standard looks at a CAP based solely on dry bulb temperature at the time of a freezing event. If a unit is designed to zero degrees and a 20-mph wind speed and it fails at 5 degrees with the 40-mph wind speed, what is the CAP expectation? Why would a Generator Owner do anything beyond identifying that the conditions exceeded the design capability of the unit?

To address this issue in a meaningful manner, we propose that NERC consider focusing on having generator units to identify their proven capabilities (by design, experience or analysis) regarding (a) DBT, (b) DBT/wind combination, and (c) precipitation. This would provide the BAs with the ability to know what to expect for the forecasted weather and not be surprised when generation fails because the weather is beyond the one of the capabilities identified. Until that level of understanding and expectations are understood, the BAs will continue to claim the issues are all caused by generation because the BA did not know something was wrong.

To compliment this change, we propose that the SDT modify the definition of Generator Cold Weather Reliability Event accordingly.

In summary, the current proposal does not allow for an entity to meet a design criteria because the SDT has focused solely on temperature. Precipitation should stand separate from temperature/wind. None of the loss-of-firm-load incidents that gave rise to EOP-012 were caused by precipitation*; they all involved extreme cold combined with high winds.

* Winter Storm Uri began with an ice storm that took out the wind turbines of northern Texas, but the fossil fleet ramped-up and there was no problem. Blackouts did not occur until the weather later became very cold and breezy.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer

Answer	No
Document Name	

Comment

Minnesota Power supports the North American Generator Forum’s (NAGF) comments.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen

Answer	No
Document Name	

Comment

ISO-NE supports the SRC comments.

Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NV Energy does not agree that the proposed requirement R1 language accounts for the effects of precipitation and the accelerated cooling effect of wind when providing temperature data as per Key Recommendation 1c.

1.2.2 requires a GO to identify generating unit minimum temperature by 1 of three methods. Two of these methods only require providing data on concurrent wind speed and precipitation if available, and the third method requires a concurrent wind speed and precipitation to be considered but does not specify to what extent wind speed and precipitation must be considered. This approach does not account for effects of precipitation and the accelerated cooling effect of wind, it merely requires a point in time observation. For example, if a plant had an observed minimum "Historical operating temperature" of 0°F with a concurrent wind speed of 5mph, this would be the reported condition, regardless of if 2 hours prior there was a 10-hour period of time with a temperature of 3°F with a concurrent wind speed of 20mph. The secondary scenario would most certainly have a greater rate of heat loss and high risk of reliability impacts due to extreme cold weather; however, the first scenario is what would be required to be recorded per 1.2.2. This failure to account for the impacts of heat loss due to wind and/or precipitation could have real and negative impacts to the reliability of the Bulk Electric System as Balancing Authorities will have incomplete data regarding the Capability and Availability of generating units across the spectrum of operating conditions that could be parameterized by accounting for the heat loss (or cooling effect) experienced by a plant due to the combination of wind, precipitation, and temperature.

Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	

Properly identifying capability and unit min operating temperature is dependent not only on temperature but various wind speeds and precipitation. This information is not readily available for older existing generators and varies over different conditions. It will be difficult to provide accurate information to the BAs based on a single point. Currently the standard only looks at dry bulb temperature for determining the ECWT, associated critical components, and associated protection to cover these components. There is a gap in expectations and understanding how these parameters are used either with or in lieu of ECWT in the standard. This language unfortunately creates confusion regarding how and when it is applied. The standard needs to better express how these parameters are related, when each is used (in a CAP or as an initial declaration to the RC/BA), and how compliance will be measured.

Likes 0	
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	No
Document Name	

Comment

Properly identifying capability and unit min operating temperature is dependent not only on temperature but various wind speeds and precipitation. This information is not readily available for older existing generators and varies over different conditions. It will be difficult to provide accurate information to the BAs based on a single point. Currently the standard only looks at dry bulb temperature for determining the ECWT, associated critical components, and associated protection to cover these components. There is a gap in expectations and understanding how these parameters are used either with or in lieu of ECWT in the standard. T his language unfortunately creates confusion regarding how and when it is applied. The standard needs to better express how these parameters are related, when each is used (in a CAP or as an initial declaration to the RC/BA), and how compliance will be measured.

Likes 0	
Dislikes 0	

Response

Imane Mrini - Austin Energy - 6

Answer	No
Document Name	

Comment

Austin Energy proposes a modification to R1.2.2 (bullet 2) to add the word "continuous"

Historical operating temperature at least one CONTINUOUS hour in duration, and if available, concurrent wind speed and precipitation; or

Likes 0	
Dislikes 0	

Response

Tony Hua - Austin Energy - 4

Answer	No
Document Name	
Comment	

Austin Energy proposes a modification to R1.2.2 (bullet 2) to add the word "continuous"

Historical operating temperature at least one CONTINUOUS hour in duration, and if available, concurrent wind speed and precipitation;

Likes 1	Austin Energy, 6, Mrini Imane
Dislikes 0	
Response	

Lovita Griffin - Austin Energy - 3	
Answer	No
Document Name	
Comment	

Austin Energy proposes a modification to R1.2.2 (bullet 2) to add the word "continuous"

- Historical operating temperature at least one CONTINUOUS hour in duration, and if available, concurrent wind speed and precipitation; or

Likes 1	Austin Energy, 6, Mrini Imane
Dislikes 0	
Response	

Michael Dillard - Austin Energy - 5	
Answer	No
Document Name	
Comment	

Austin Energy proposes a modification to R1.2.2 (bullet 2) to add the word "continuous":

Historical operating temperature at least one CONTINUOUS hour in duration, and if available, concurrent wind speed and precipitation;

Likes 1	Austin Energy, 6, Mrini Imane
Dislikes 0	
Response	

Daniel Roethemeyer - Vistra Energy - 5	
Answer	No
Document Name	
Comment	
We agree with the NAGF comments	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	No
Document Name	
Comment	
Weather records for many locations will not have data sufficient to consider these factors, as such during audits entities will somehow have to show that data wasn't available and justify why this information is not included.	
Likes 0	
Dislikes 0	
Response	

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
MRO NSRF does not agree that the proposed requirement R1 language accounts for the effects of precipitation and the accelerated cooling effect of wind when providing temperature data as per Key Recommendation 1c. 1.2.2 requires a GO to identify generating unit minimum temperature by 1 of three methods. Two of these methods only require providing data on concurrent wind speed and precipitation if available, and the third method requires a concurrent wind speed and precipitation to be considered but does not specify to what extent wind speed and precipitation must be considered. This approach does not account for effects of precipitation and the accelerated cooling effect of wind, it merely requires a point in time observation. For example, if a plant had an observed minimum “Historical operating temperature” of 0°F with a concurrent wind speed of 5mph, this would be the reported condition, regardless of if 2 hours prior there was a 10-hour period of time with a temperature of 3°F with a concurrent wind speed of 20mph. The secondary scenario would most certainly have a greater rate of heat loss and high risk of reliability impacts due to extreme cold weather; however, the first scenario is what would be required to be recorded per	

1.2.2. This failure to account for the impacts of heat loss due to wind and/or precipitation could have real and negative impacts to the reliability of the Bulk Electric System as Balancing Authorities will have incomplete data regarding the Capability and Availability of generating units across the spectrum of operating conditions that could be parameterized by accounting for the heat loss (or cooling effect) experienced by a plant due to the combination of wind, precipitation, and temperature.

Likes 0	
Dislikes 0	

Response

Thomas Standifur - Austin Energy - 1

Answer	No
Document Name	

Comment

Austin Energy proposes a modification to R1.2.2 (bullet 2) to add the word "continuous"

Historical operating temperature at least one CONTINUOUS hour in duration, and if available, concurrent wind speed and precipitation; or

Likes 1	Austin Energy, 6, Mrini Imane
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	No
Document Name	

Comment

PGAE agrees and supports the NAGF comments.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment	
R1.2.2 Bullet 3 – Add “if available”; strike “which includes”: Current cold weather performance temperature determined by an engineering analysis, “if available”, " " concurrent wind speed and precipitation. Suggest changes due to the availability of data.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
This is simply requiring us to perform a wind chill calculation, with an ambiguous 20mph wind speed. Why are we not basing this on the calculations we have available from the ASOS or NWS data that we have already had to complie under EOP 012-1. Some regions or facilities are more protected from wind effects than others, and there is no direct correlation between extreme cold weather tempeartures and wind so why are we trying to model something that has no technical basis.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation does not agree. Reclamation Hydro generators are not designed by taking into account concurrent wind speed and precipitation as they are protected internally to a physical structure and do not have environmental constraints. The amount of precipitation or wind speed has no effect on these units and should be removed from this standard. Also, depending on the unforeseen combination of wind, precipitation and temperature, it is impossible to predict variants in each from one hour to the next.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	

Answer	No
Document Name	

Comment

In R1, the only place wind and precipitation are mentioned is under 1.2.2 (design information, actual operating information and engineering analysis), and as concurrent data for a worst-case temperature. It does not follow that references to “freezing” in the standard include three different phenomena: actual freezing (water turning to ice), malfunctions cause by fluids becoming too viscous (technically this is congealing, not freezing, but it’s functionally equivalent) and accretion/accumulation of moisture (such as blade icing on a wind turbine, snow accumulation on solar panels or ice accumulating on the air inlets of a gas turbine) which is not a form of freezing. If this is the intent, the SDT needs to define the term “freezing” so that all parties are clear on what is covered in the standard.

Such a wide-ranging definition would be a mistake, however. The effect of low temperature and wind in causing freezing or congealing stands separate from precipitation-related problems. The ice storms that knock wind turbines offline occur near 32 F, for example, and have nothing to do with ability to operate at the ECWT. None of the loss-of-firm-load incidents that gave rise to EOP-012 was caused by precipitation*; they all involved extreme cold combined with high winds. Precipitation-related obligations in EOP-012 should be of a solely informative nature, not prescriptive.

* Winter Storm Uri began with an ice storm that took out the wind turbines of northern Texas, but the fossil fleet ramped-up to cover the losses and there was no problem. Blackouts did not occur until the weather later became very cold and breezy.

NERC should focus on getting existing plants to identify their proven capabilities for existing units (by design, experience or analysis) regarding (a) DBT, (b) DBT/wind combination, and (c) precipitation. BAs would then know what to expect for the forecasted weather and not be surprised when generation fails because the weather is beyond the one of the capabilities identified.

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3

Answer	No
Document Name	

Comment

This is simply requiring us to perform a wind chill calculation, with an ambiguous 20mph wind speed. Why are we not basing this on the calculations we have available from the ASOS or NWS data that we have already had to complie under EOP 012-1. Some regions or facilities are more protected from wind effects than others, and there is no direct correlation between extreme cold weather tempeartures and wind so why are we trying to model something that has no technical basis.

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power recommends editing the third bullet in R1.2.2 to make it clear that the engineering analysis is not looking at concurrent wind speed and precipitation from historical operating temperature data (see proposed mark-up below). Instead, the engineering analysis is considering performance limitations imposed by concurrent wind speed and precipitation. R1.2.2, third bullet: *Current cold weather performance temperature determined by an engineering analysis, which includes* ***limitations*** *on concurrent wind speed and precipitation.*	
Likes 1	Platte River Power Authority, 3, Kiess Richard
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	No
Document Name	NAGF EOP-012-2 Comment Form Draft 3.docx
Comment	
Likes 0	
Dislikes 0	
Response	

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
SIGE recommends adding “Calendar” before the words “Year” and “Month” – similar to PRC-005 language.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
It is suggested that “and engineering analysis, operating data or design information” in M1 be changed to “and design information, operating data or engineering analysis” to be consistent with the sequence in R1.2.2.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation agrees, wording provides sufficient flexibility to allow context for minimum temperature conditions so that wind and precipitation conditions different than historical can be used in planning for actual future events. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation agrees, wording provides sufficient flexibility to allow context for minimum temperature conditions so that wind and precipitation conditions different than historical can be used in planning for actual future events. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM agrees that the language in proposed Requirement R1 aligns with Key Recommendation 1c.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees the proposed language in R1 accounts for Recommendation 1c.	
Likes 0	
Dislikes 0	

Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - 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 that the proposed language in R1 aligns with Key Recommendation 1c.	
Likes 0	
Dislikes 0	
Response	

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy group supports EEIs comments.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG agrees with NPCC/RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 3, 1; - Patricia Robertson, Group Name BC Hydro Balloters	
Answer	Yes
Document Name	
Comment	
Recommend adding the word “calendar” to Requirement R1 so it reads: “At least once every five calendar years ….”. This would provide clarity on the bookends of the task and aligns with the approach used in other standards such as PRC-002-2 R5.4.	
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 - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, 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	
Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5,6	
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	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 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	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
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	
Abbas Munir - Bruce Power - 5 - NPCC	
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	

Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laura Hankins - Laura Hankins On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - Laura Hankins	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Regarding the second bullet in Requirement Part 1.2, Texas RE recommends including a provision for documenting the reason(s) why concurrent wind speed and precipitation are not available.	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Joseph Gatten On Behalf of: Nicholas Friebel, Xcel Energy, Inc., 5, 3, 1; - Joseph Gatten	
Answer	
Document Name	
Comment	

Xcel Energy believes that improvements to the proposed Requirement R1 language should be made to provide additional clarity. Please refer to EEI comments in response to question 9 of the comment form.

Likes 0	
Dislikes 0	

Response

3. Do you agree that the proposed date of October 1, 2027 is an appropriate time frame for units that enter commercial operation after this date to implement the enhanced cold weather requirements that are contained within Requirement R2? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Daniel Herring - DTE Energy - Detroit Edison Company - 3	
Answer	No
Document Name	
Comment	
Comments: This date should be determined as part of the Implementation Plan upon the standard being approved and effective as opposed to a fixed date. For example, number of months after effective date.	
Likes 1	Luminant - Luminant Energy, 6, Ferrell Russell
Dislikes 0	
Response	

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, 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 October 1, 2027 is an appropriate time frame. This time frame could significantly delay or increase costs for new projects currently planned or underway. Tacoma Power recommends deleting “commercial operation” and replacing with “units built after this date”.	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation does not agree, as it is not defined whether new or existing units are required to meet R2 to enter commercial operation. Recommend that Commercial Operation be capitalized as defined in the Glossary of Terms.	

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

no.

Likes 0	
Dislikes 0	

Response

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1

Answer	No
Document Name	

Comment

The drafting team has not shown sufficient technical basis for the implementation for October 1, 2027

Likes 0	
Dislikes 0	

Response

Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group

Answer	No
Document Name	

Comment

Buckeye supports the comments of ACES:

Design decisions for new generating units and/or facilities are made well in advance of the start of construction. In many cases, design decisions are made years in advance. Under the currently proposed language in R2.1.3, the GO must install freeze protection measures that provide the ability to operate for 12 continuous hours at the unit(s) Extreme Cold Weather Temperature with a sustained concurrent twenty (20) mph wind speed on any

exposed Generator Cold Weather Critical Components. This requirement will likely cause the GO to either make significant design changes to comply with this requirement. In short, the GO will need to either install additional freeze protection measures or to build enclosures to house any critical components. This requirement will cause the GO to either incur significant additional design and/or construction costs or to expedite the schedule(s) for any in progress project(s). We recommend a five (5) year phased compliance approach for Requirement R2. Using the current compliance date for EOP-012-1, the new recommended date is October 1, 2029.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
ISO-NE supports the SRC comments that R2 and R3 should be combined to include all units and by doing so would result in a more reliable and performant BES during extreme cold weather conditions.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC signed on to ACES comments: Design decisions for new generating units and/or facilities are made well in advance of the start of construction. In many cases, design decisions are made years in advance. Under the currently proposed language in R2.1.3, the GO must install freeze protection measures that provide the ability to operate for 12 continuous hours at the unit(s) Extreme Cold Weather Temperature with a sustained concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components. This requirement will likely cause the GO to either make significant design changes to comply with this requirement. In short, the GO will need to either install additional freeze protection measures or to build enclosures to house any critical components. This requirement will cause the GO to either incur significant additional design and/or construction costs or to expedite the schedule(s) for any in progress project(s). We recommend a five (5) year phased compliance approach for Requirement R2. Using the current compliance date for EOP-012-1, the new recommended date is October 1, 2029.	
Likes 0	
Dislikes 0	

Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
The proposed date of October 1, 2027 is based on the effective date of October 1, 2024. For those jurisdictions where regulatory approval is required, the Standard effective date may be later than October 1, 2027. It is suggested to change "October 1, 2027" to "36 months after the effective date of this Standard".	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
The SRC disagrees that the enhanced cold weather requirements that are contained within Requirement R2 should be limited to units that enter commercial operation after October 1, 2027. Requirements R2 and R3 should be combined into a single Requirement that applies the enhanced cold weather requirements currently contained within Requirement R2 to all units. The Generator Cold Weather Constraint declaration process and the Corrective Action Plan process within EOP-012 provide sufficient accommodation for existing units. Adopting the SRC's proposal would require more thorough weatherization of generation units, resulting in a more reliable and performant BES during extreme cold weather conditions.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Contracts for new units are currently being issued with commercial operation dates after 10/1/2027. Also, some existing contracts for new units are being delayed past 10/1/27 due to manpower and equipment supply chain issues. These contracts do not neccesarly include all the cold weather	

requirements from this standard. Changing the contracts would at the minimum be expensive and, at the worst may not be possible. Therefore we suggest the date be pushed out to 10/1/30.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
Given we are not in support of these changes as written, the proposed date needs to be reconsidered after further evaluation of 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	
Design decisions for new generating units and/or facilities are made well in advance of the start of construction. In many cases, design decisions are made years in advance. Under the currently proposed language in R2.1.3, the GO must install freeze protection measures that provide the ability to operate for 12 continuous hours at the unit(s) Extreme Cold Weather Temperature with a sustained concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components. This requirement will likely cause the GO to either make significant design changes to comply with this requirement. In short, the GO will need to either install additional freeze protection measures or to build enclosures to house any critical components. This requirement will cause the GO to either incur significant additional design and/or construction costs or to expedite the schedule(s) for any in progress project(s). We recommend a five (5) year phased compliance approach for Requirement R2. Using the current compliance date for EOP-012-1, the new recommended date is October 1, 2029.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG agrees with NPCC/RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
While this date may impact some units already planned, the CAP process addresses the potential issues. There may be some negative impacts caused by the slow interconnection process being experienced but the fixed date provides all entities reasonable notice.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	

FirstEnergy does believe this is sufficent time.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports EEIs comments.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - 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 and agrees the proposed date of October 1, 2027 is an appropriate timeframe.	
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	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PGAE agrees and supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
MRO NSRF agrees that the proposed date of October 1, 2027, is appropriate.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	

Response	
Daniel Roethemeyer - Vistra Energy - 5	
Answer	Yes
Document Name	
Comment	
We agree with the NAGF comments	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
While this date may impact some units already planned, the CAP process addresses the potential issues. There may be some negative impacts caused by the slow interconnection process being experienced but the fixed date provides all entities reasonable notice.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
While this date may impact some units already planned, the CAP process addresses the potential issues. There may be some negative impacts caused by the slow interconnection process being experienced but the fixed date provides all entities reasonable notice.	
Likes 0	
Dislikes 0	

Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the proposed date of October 1, 2027 as an appropriate timeframe.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
NV Energy agrees that the proposed date of October 1, 2027, is appropriate.	
Likes 0	
Dislikes 0	
Response	

Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM supports the proposed date of October 1, 2027.	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments Alison Mackellar 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	Yes
Document Name	
Comment	
While this date may impact some units already planned, the CAP process addresses the potential issues. There may be some negative impacts caused by the slow interconnection process being experienced but the fixed date provides all entities reasonable notice.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports NAGF comments on this question.	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Joseph Gatten On Behalf of: Nicholas Friebel, Xcel Energy, Inc., 5, 3, 1; - Joseph Gatten	
Answer	Yes
Document Name	
Comment	
Xcel Energy agrees with the timeline identified in R2. We also support comments offered by EEI in response to question 9 of the comment form.	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	

Answer	Yes
Document Name	
Comment	
AES CE supports the proposed date.	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
SIGE supports the proposed date of October 1, 2027 in R2.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 3, 1; - Patricia Robertson, Group Name BC Hydro Balloters	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Hankins - Laura Hankins On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - Laura Hankins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
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 Standifur - Austin Energy - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Abbas Munir - Bruce Power - 5 - NPCC	
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	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 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	
Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, 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	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

4. The SDT structured R2.1 and R2.2 in the vein of an if/then statement. The intent being, if a GO implements R2.1, then they would be compliant with Requirement R2. If a GO does not implement R2.1 but implements R2.2, then they would be compliant with Requirement R2. Stated differently, a GO would only risk non-compliance with Requirement R2 if they did neither R2.1 nor R2.2. Does the proposed language, as drafted by the SDT, provide that clarity and reflect the SDT's intent as stated above? If not, please provide suggested clarifying language.

Mike Magruder - Avista - Avista Corporation - 1

Answer	No
Document Name	

Comment

This 'and/or' or 'if/then' option is not implied in the standard as currently drafted. Additional clarity would be beneficial.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

We suggest adding additional clarification to the end of Requirement R2 so that it states, "…*required to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius), shall **meet either Part 2.1 or Part 2.2 below**:*".

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt

Answer	No
Document Name	

Comment

Black Hills Corporation agrees and supports NAGF comments.

Likes 0	

Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees and supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees and supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees and supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
The SRC believes that Requirement R2 would more clearly reflect the SDT’s intent that a GO that has not implemented Part 2.1 can achieve compliance with Requirement R2 by implementing Part 2.2 if Part 2.2 were revised to read as follows: “Each Generator Owner that does not have freeze protection measures as required by Requirement R2 Part 2.1 **may comply with this requirement by developing and implementing** a Corrective Action Plan.”	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
It is better to state clearly in R2 that only R 2.1 or R 2.2 is required. It is not clear if freeze protection measures are required when Generator Cold Weather Critical Components are inside the heated powerhouse at units’ Extreme Cold Weather Temperature. It is suggested that R 2.1 be changed to: 2.1 Have freeze protection measures to protect Generator Cold Weather Critical Components that provide the capability to operate at the unit(s)’ Extreme Cold Weather Temperature: 2.1.1 For (i) a period of not less than twelve (12) continuous hours, or (ii) the maximum operational duration for intermittent energy resources if less than twelve (12) continuous hours; and 2.1.2 With a sustained concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components. It is suggested that the first sentence of M2 be changed to:	

Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with Requirement R2.1, or it has developed a Corrective Action Plan for the identified issues in accordance with Requirement R2.2.	
Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
The way 2.1 is currently written, you have to satisfy 2.1. Recommend adding language similar to the bullet point in R1 of PRC-024-3.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
Enel North America Inc. does not believe Requirement R2 provides the intent of an if/then statement as currently written. Enel suggests following the MRO NSRF recommendation of following the either/or method utilized in PRC-002 R12 to accomplish the intent of the SDT.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports NAGF comments on this question.	

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 R2.1 deals solely with dry bulb temperature and wind, leaving “freezing” in the form of precipitation-related vulnerabilities unaddressed and therefore causing confusion when compared to the intermingled concept of “freezing” currently used by the standard. Precipitation should be handled separately from freezing, and only in an informative (not prescriptive) manner. There are snow-*resistant* inlet air filters, and many are experimenting with accretion-*resistant* wind turbine blades, but one ultimately is dealing with degrees of risk and not certainties. This is especially the case when considering the many variabilities involved (dry fluffy snow vs heavy wet snow, snowstorm vs ice storm, 12” of snow at 1 in/hr for 12 hours versus 4 hours at 3 in/hr, wind from the east or from the west etc.).

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer

Answer	No
Document Name	

Comment

Minnesota Power supports the North American Generator Forum’s (NAGF) comments.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC

Answer	No
Document Name	

Comment

PNM recommends including “**or**” for R2.1 or R2.2 that demonstrates compliance if either R2.1 or R2.2 is completed, similar to PRC-002-2 R12.

Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	

ISO-NE supports the SRC comments.

Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NV Energy agrees with the stated intent of R2. However, NV Energy does not agree that the proposed if/then method that the SDT attempted to implement in R2 is capable of accomplishing this intent. As currently written, there is no language that removes the obligation of compliance with R2.1 while developing a CAP as required by R2.2. NV Energy suggests that the SDT review PRC-002 R12. PRC-002-2 R12 utilizes an either/or approach regarding EITHER meeting a certain required capability OR developing a CAP to allow for meeting of the required capability.

Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	

NRG doesn't have a concern with the if/then scenario. However, under R2.1, the identified critical components are required to have appropriate freeze protection measures to protect to the ECWT (a single point of dry bulb temp). However, this requirements adds a 20 mph requirement which can be confusing. As stated above clarification should be made to better declare when these additional parameters should be considered.

Likes 0	
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	No
Document Name	

Comment

NRG doesn't have a concern with the if/then scenario. However, under R2.1, the identified critical components are required to have appropriate freeze protection measures to protect to the ECWT (a single point of dry bulb temp). However, this requirements adds a 20 mph requirement which can be confusing. As stated above clarification should be made to better declare when these additional parameters should be considered.

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	No
Document Name	

Comment

SMUD and BANC agree with the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Lovita Griffin - Austin Energy - 3

Answer	No

Document Name	
Comment	

Austin Energy comments on R2.1.3

This requirement as written is somewhat onerous. It should be treated as a wind chill factor and GOs would have to meet a temperature that, with the addition of a 20mph constant wind, would reach a wind chill temperature equal to the ECWT.

Likes 0	
Dislikes 0	
Response	
Tony Hua - Austin Energy - 4	
Answer	No
Document Name	
Comment	

Austin Energy comments on R2.1.3

This requirement as written is somewhat onerous. It should be treated as a wind chill factor and GOs would have to meet a temperature that, with the addition of a 20mph constant wind, would reach a wind chill temperature equal to the ECWT.

Likes 1	Austin Energy, 6, Mrini Imane
Dislikes 0	
Response	
Imane Mrini - Austin Energy - 6	
Answer	No
Document Name	
Comment	

This requirement as written is somewhat onerous. It should be treated as a wind chill factor and GOs would have to meet a temperature that, with the addition of a 20mph constant wind, would reach a wind chill temperature equal to the ECWT.

Likes 0	
Dislikes 0	
Response	

Daniel Roethemeyer - Vistra Energy - 5	
Answer	No
Document Name	
Comment	
We agree with the NAGF comments	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	No
Document Name	
Comment	
It is not strongly worded enough to provide assurance that this will be treated as an if-then statement by the Auditors.	
Likes 0	
Dislikes 0	
Response	

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
MRO NSRF agrees with the stated intent of R2. However, MRO NSRF does not agree that the proposed if/then method that the SDT attempted to implement in R2 is capable of accomplishing this intent. As currently written, there is no language the removes the obligation of compliance with R2.1 while developing a CAP as required by R2.2. MRO NSRF suggests that the SDT review PRC-002 R12. PRC-002-2 R12 utilizes an either/or approach regarding EITHER meeting a certain required capability OR developing a CAP to allow for meeting of the required capability.	
Likes 0	
Dislikes 0	
Response	

Thomas Standifur - Austin Energy - 1	
Answer	No
Document Name	
Comment	
This requirement as written is somewhat onerous. It should be treated as a wind chill factor and GOs would have to meet a temperature that, with the addition of a 20mph constant wind, would reach a wind chill temperature equal to the ECWT.	
Likes 1	Austin Energy, 6, Mrini Imane
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State would like to recommend the following verbiage for R2: R2. Applicable to generating units with a commercial operation date or after October 1, 2027: Each Generator Owner, for each generating unit that has a calculated ExtremeCold Weather Temperature at or below 32 degrees Fahrenheit (zero degrees Celsius)as determined in Requirement R1, and that self-commits or is required to operate ator below a temperature of 32 degrees Fahrenheit (zero degrees Celsius),(1) shall have freeze protection measures as described in Part 2.1 or develop a Corrective Action Plan as described in Part 2.2.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PGAE agrees and supports the NAGF comments.	
Likes 0	

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

Modify R2 to add “shall perform R2.1 or R2.2” as follows:

R2. Applicable to generating units with a commercial operation date on or after October 1, 2027: Each Generator Owner, for each generating unit that has a calculated Extreme Cold Weather Temperature at or below 32 degrees Fahrenheit (zero degrees Celsius) as determined in Requirement R1, and that self-commits or is required to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius), “shall perform R2.1 or R2.2”: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]

Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	

this and/or or if/then option is not implied in the standard as currently drafted. Additional clarity would be beneficial.

Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

R2.1 deals solely with dry bulb temperature and wind, leaving “freezing” in the form of precipitation-related vulnerabilities unaddressed and therefore causing confusion. Precipitation should be handled separately from freezing, and in only an informative (not prescriptive) manner, since one cannot obtain vendor guarantees in this respect. There are snow-*resistant* inlet air filters, and many are experimenting with accretion-*resistant* wind turbine

blades, but one ultimately is dealing with degrees of risk and not certainties. This is especially the case when considering the many variabilities involved - dry fluffy snow vs heavy wet snow, snow storm vs ice storm, 12" of snow at 1 in/hr for 12 hours vs 4 hours at 3 in/hr, wind from the east or for the west etc.

Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
no, this and/or or if/then option is not implied in the standard as currently drafted. Additional clarity would be beneficial.	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	No
Document Name	NAGF EOP-012-2 Comment Form Draft 3.docx
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	
While we believe the proposed language provides the intended clarity. We recommend using an "or" statement as in other requirements to further emphasize the intent. For an example, see the proposed language in R1.2.2.	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
SIGE agrees that the proposed language is sufficient to clarify the Standard Drafting Team's if/then intent.	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
While AES CE agrees with the proposed language, we also want to caution that high wind and cold temperatures do not always equate to freezing. Precipitation also plays an important role in freezing.	
Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	

AEPC signed on to ACES comments:

While we believe the proposed language is provides the intended clarity, we recommend using an "or" statement as in other requirements to further emphasize the intent. For an example, see the proposed language in R1.2.2.

Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	

Constellation agrees the logic seems to work

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	

Constellation agrees the logic seems to work

Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the intent of R2.1 and R2.2.	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
While the SDT's intended relationship between R2 Part 2.1 and R2 Part 2.2 is clear, RF recommends one of the following additions to prevent misunderstanding or misapplication: • Before the R2 VRF and Time Horizon, replace "shall:" with "shall meet either Part 2.1 and the associated sub-Parts or Part 2.2:" OR • Begin Part 2.2 with "Unless developing a Corrective Action Plan, have freeze protection measures…"	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	

ITC supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company agrees that the language in R2.1 and R2.2 align with the SDT's intent.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	

WEC Energy group supports EEIs comments.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	Yes
Document Name	

Comment

OPG agrees with NPCC/RSC's comments.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	

Comment

AEP's reply of "yes" to Question #4 is driven by our understanding that if an event takes place involving new generation, that an entity may develop a CAP and follow the associated process. Is our interpretation correct in this regard?

Likes 0	
Dislikes 0	

Response

Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 3, 1; - Patricia Robertson, Group Name BC Hydro Balloters

Answer	Yes
Document Name	

Comment

Requirement R7 allows for Generator Cold Weather Constraints. It’s conceivable that Requirement R2.2 may have a Corrective Action Plan that can’t be implemented under Requirement R7 due to Constraints. Would this scenario be considered compliant?

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, 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

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5,6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Devon Tremont - Taunton Municipal Lighting Plant - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Colin Chilcoat - Invenergy LLC - 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	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Abbas Munir - Bruce Power - 5 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Laura Hankins - Laura Hankins On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - Laura Hankins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, 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	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Joseph Gatten On Behalf of: Nicholas Friebel, Xcel Energy, Inc., 5, 3, 1; - Joseph Gatten	
Answer	
Document Name	
Comment	
Xcel Energy supports comments offered by EEI in response to question 9 of the comment form.	
Likes 0	
Dislikes 0	
Response	
Michael Dillard - Austin Energy - 5	
Answer	
Document Name	
Comment	
Austin Energy comments on R2.1.3: This requirement as written is somewhat onerous. It should be treated as a wind chill factor and GOs would have to meet a temperature that, with the addition of a 20mph constant wind, would reach a wind chill temperature equal to the ECWT.	
Likes 0	
Dislikes 0	
Response	

5. The SDT proposes two timeframes, 24 months for addressing existing equipment or freeze protection and 48 months for implementing new equipment or freeze protection, for Corrective Action Plans in Requirement R7. Do you agree that the timeframes proposed are appropriate? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

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

Answer	No
Document Name	

Comment

Tacoma Power is concerned with potential impacts of supply chain delays in meeting this timeframe. Flexibility should be allowed in the Requirement to account for these unexpected delays. Recent supply chain delays caused significant challenges for implementing CIP-012-1 and as a result, alternative protections needed to be developed in order to meet the effective date. Tacoma Power recommends adding a sub-Requirement that would allow entities to request additional time to be compliant if there’s unforeseen delays. For example: “R.7.1.2.1 If unforeseen delays outside of the Entities’ control arise, then Entities should report the delays and revised CAP date to ERO Enterprise.”

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

Question #5 includes the word “implementing” in regards to new protection measures, however, this word this is not used within R7 itself. AEP proposes that the wording for 7.1.1 & 7.1.2 be revised as follows, which we believe will provide the needed clarity.

7.1 Include a timetable for *implementing* the selected corrective action(s) that shall:

7.1.1 Be completed within 24 months *of CAP development* if the corrective actions involve existing freeze protecting measures/equipment

7.1.2 Be completed within 48 months *of CAP development* if the corrective actions involve new freeze protecting measures/equipment.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

It is impossible to fully understand what it is that a Generator Owner is being asked to do at this time, due to the issues discussed above. If the SDT can provide better guidance or clearer requirements, then the time horizons can be better understood.

Additionally, since a GO may have to address hundreds of wind turbine, thousands of solar panels or a large number of conventional units, it is impossible to say how long it will take to fund modifications, find resources to perform the work, and schedule outages with the BAs to allow work to be completed.

While the proposed time limits have been used by NERC in standards, specifically TPL-007, we note that TPL-007 requires a CAP only for a single unit, not a fleet of units, in addition to being very limited in the scope rather than open to any possible cause of a trip, derate or failure to start. Due to this significant difference, a limited time frame in the style of TPL-007 is impractical, despite the fact that FERC pointed to TPL-007. A CAP addressing an entire fleet may require a certain period of time for planning and design work, then a rolling effort to modify units one by one – say half a year to retrofit one unit, two years for four, and four years for eight.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	No
Document Name	

Comment

Reclamation does not agree. Addressing existing equipment upgrades as well as Implementation of new equipment are time and cost burden actions that can vary based on funding, equipment availability, manpower, industry limitations and other unforeseen items. Recommend 36 months for existing and 60 months for new equipment.

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 supports the NAGFs comments.

Likes 0	
Dislikes 0	
Response	

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	No
Document Name	
Comment	
PGAE agrees and supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	
What is considered new eqiupment per 7.1? Would this be brand new equipment for the facility or a new piece of equipment for the CAP in 7.1?	
Likes 0	
Dislikes 0	
Response	

Abbas Munir - Bruce Power - 5 - NPCC

Answer	No
Document Name	
Comment	

This time frame may not be sufficient to address freeze protection measures for a multi-unit generator facilities hence there should be a provision for MP to work with the balancing authority to develop and agree on a schedule for corrective action implementation.

Likes 0	
Dislikes 0	

Response

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1

Answer	No
Document Name	

Comment

Smaller entities that have multiple projects need to go through a buget process and need time to implement corrections throughout their fleet. Smaller entites will find this a significant burden.

Likes 0	
Dislikes 0	

Response

Daniel Roethemeyer - Vistra Energy - 5

Answer	No
Document Name	

Comment

We agree with the NAGF comments

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen

Answer	No
Document Name	

Comment

ISO-NE supports the SRC comments and recommends adding language to R7.1.1 and 7.1.2 that provides a timeline for CAP completion. ISO-NE proposes 12 months from CAP development with an allowance of 24 months if the installation of new freeze protection equipment is required.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	No
Document Name	
Comment	
PNM recommends a clarifying statement for the timeline related to new freeze protection on existing equipment. Is the intent to have the timeline in this scenario be 24 months or 48 months. PNM would support a 48 month timeline for all new freeze protection measures on existing equipment.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer	
Answer	No
Document Name	
Comment	
Minnesota Power supports the North American Generator Forum's (NAGF) comments.	
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 supports the desire to have separate deadlines for repairs and new implementation. However, the NAGF has concerns about the proposed time limits as follows:

a. For the reasons stated above related to wind and precipitation, the NAGF believes it is impossible to fully understand what it is that a Generator Owner is being asked to do at this time based on the language in the standard. If the SDT can provide better guidance or clearer requirements, then the time horizons can be better understood.

b. Additionally, since the CAP may have to address anywhere from 1 to 1000 wind turbines, solar panels or a large number of individual thermal units, it is impossible to say how long it will take to fund modifications, find resources to perform the work, and schedule outages with the BAs to allow work to be completed, all while attempting to complete ongoing maintenance to allow generators to run.

c. While these time limits have been used by NERC in previous standards, specifically TPL-007, we note that TPL-007 requires a CAP only for a single unit, not a fleet of units in addition to being very limited in the scope of the issue to be covered rather than open to any possible cause of a trip, derate or failure to start. Therefore, the scope of a CAP under TPL-007 is very limited while the scope of the CAPs envisioned under EOP-012 will vary greatly as the CAP is not limited to a single unit or even a single plant. Due to this significant difference, a hard time frame is unacceptable. Either the scope of the CAP must be limited to a single unit (similar to TPL-007), or at most a single plant, or the time period to complete the CAP needs to be modified to allow an amount of time per unit identified, instead of a time limit for the entire CAP.

d. While we understand that NERC and FERC have determined that addressing cold weather is a high priority, if Generator Owners are unable to either afford or complete required maintenance because cold weather issues take priority, then the generators will likely have forced outages before the units experience cold weather-related outages.

For these reasons, the NAGF asks that the SDT goes back and looks at the FERC order related to EOP-012 in a more reasonable manner. While we understand that FERC pointed to TPL-007, that does not mean TPL-007 provides a reasonable framework for EOP-012. While we do not believe a CAP should have 4 years for each unit identified, it would not be unreasonable for an additional year or two to be included in the CAP for each unit identified. As an example, assuming an additional year per unit is determined reasonable, when the Generator Owner identifies two units that have a similar vulnerability, then the CAP would have three years or five years, depending on the type of issue.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

Ameren agrees with and supports NAGF comments on this question.

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	
Comment	

AES CE supports NAGF's comments in regards to this question. While AES CE appreciates the SDT's proposed timeline to address existing equipment and new equipment, the issue at hand is the concern of the inability to complete the Corrective Action Plan due to labor resources as well as equipment availability. Additionally, outages that need to be taken within the proposed timeline may create constraints in operations and impact reliability as well. So, 24 months and 48 months may not be sufficient to address what needs to be implemented for the CAP that will be developed.

Likes 0	
Dislikes 0	
Response	

Don Cribb - Santee Cooper - 5, Group Name Santee Cooper

Answer	No
Document Name	
Comment	

The 24 months specified by this plan is only sufficient if it is not concurrent with the time period specified by the Implementation Plan but is in addition to those times.

Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

For the reasons discussed in its response to question 9, the SRC believes these timeframes should be 12 months and 24 months, respectively, rather than 24 months and 48 months.

Likes 0	
Dislikes 0	
Response	

Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation (BHC) is concerned with the impact supply chain delays could have in meeting this time frame. BHC suggests adding a sub-requirement to allow entities to request additional time for compliance if unforeseen delays affect them.	
Likes 0	
Dislikes 0	
Response	

Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Black Hills Corporation (BHC) is concerned with the impact supply chain delays could have in meeting this time frame. BHC suggests adding a sub-requirement to allow entities to request additional time for compliance if unforeseen delays affect them.	
Likes 0	
Dislikes 0	
Response	

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation (BHC) is concerned with the impact supply chain delaiys could have in meeting this time frame. BHC sugests adding a sub-requirement to allow entities to request additional time for compliance if unforseen delays affect them.	
Likes 0	
Dislikes 0	
Response	

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	
Comment	
Black Hills Corporation (BHC) is concerned with the impact supply chain delays could have in meeting this time frame. BHC suggests adding a sub-requirement to allow entities to request additional time for compliance if unforeseen delays affect them.	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Due to the nature of nuclear power plant operations, 24 months and up to 48 months is not enough time for planning, designing, and completing the work. There should be a caveat or exemption given for sites that cannot meet these timelines. It is unclear what “existing equipment” (in 7.1.1) and “new equipment” (in 7.1.2) means. We suggest deleting the words “equipment or” in both sub-parts so that they just address freeze protection measures.	
Likes 0	
Dislikes 0	
Response	

Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	No
Document Name	NAGF EOP-012-2 Comment Form Draft 3.docx
Comment	
Likes 0	
Dislikes 0	
Response	

James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
In P 64 of the FERC order, the Commission expressed concern that a generator owner may make a constraint declaration without informing planning and operational entities (e.g., the balancing authority) that are expecting the reliable operation of the generating unit to its Extreme Cold Weather Temperature. To address this concern, the SDT has developed R8 to require the GO to provide the constraint declaration to the Balancing Authority and update the generating unit's data specification regarding operational limitations to the generator unit's capability and availability under R1.	
Likes 0	
Dislikes 0	
Response	

Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
yes, this is better clarification than what was provided in EOP 12-1	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG agrees with NPCC/RSC's comments.	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - 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 that the timeframe proposed for Corrective Action Plans for R7 provide sufficient time to address freeze protection plans.	
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	

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
MRO NSRF agrees with the timelines proposed in R7 as the R7.3 already allows for the CAP to be updated as required, including timelines.	
Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	

Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
NRG supports staggered implementation plan, however there should not always be atime limit on what is expected to be done. Multiple units at the same site requiring the same remediation at the same time may require additional time to address. Perhaps the time step should be based upon number of units. For the most part, time frames appear reasonable from an implementation viewpoint. However, the Standard subrequirement language is not clear that completion of plan needs to be completed either in 24 or 48 month period. It implies that only need to “specifiy action” within that time frame. Recommend SDT provide better clarity its intent that this is the expected completion date.	
Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
NRG supports staggered implementation plan, however there should not always be a time limit on what is expected to be done. Multiple units at the same site requiring the same remediation at the same time may require additional time to address. Perhaps the time step should be based upon number of units. For the most part, time frames appear reasonable from an implementation viewpoint. However, the Standard subrequirement language is not clear that completion of plan needs to be completed either in 24 or 48 month period. It implies that only need to “specifiy action” within that time frame. Recommend SDT provide better clarity its intent that this is the expected completion date.	

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	Yes
Document Name	

Comment

ITC supports EEI's comments.

Likes 0	
Dislikes 0	

Response

Lindsey Mannion - ReliabilityFirst - 10

Answer	Yes
Document Name	

Comment

In P 64 of the FERC order, the Commission expressed concern that a generator owner may make a constraint declaration without informing planning and operational entities (e.g., the balancing authority) that are expecting the reliable operation of the generating unit to its Extreme Cold Weather Temperature. To address this concern, the SDT has developed R8 to require the GO to provide the constraint declaration to the Balancing Authority and update the generating unit's data specification regarding operational limitations to the generator unit's capability and availability under R1.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

AZPS agrees that the timeframes proposed are appropriate.

Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
NV Energy agrees with the timelines proposed in R7 as the R7.3 already allows for the CAP to be updated as required, including timelines.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments	

Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Joseph Gatten On Behalf of: Nicholas Friebel, Xcel Energy, Inc., 5, 3, 1; - Joseph Gatten	
Answer	Yes
Document Name	
Comment	
Xcel Energy supports comments offered by EEI in response to question 9 of the comment form.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	
Enel North America Inc. agrees with the 24- and 48-month proposed timeline for existing and new freeze protection respectively but proposes the SDT clarify the timeframe from “months” to “calendar months” to align with Scenario 2 of the approved *ERO Enterprise CMEP Practice Guide, Implementation of “Annual” and “Calendar Month(s)*” in the Reliability Standards.	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
SIGE supports the intent of R7 but recommends striking “equipment” from R7.1.1 and R7.1.2.	

Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Yes, this is better clarification than what was provided in EOP 12-1.	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 3, 1; - Patricia Robertson, Group Name BC Hydro Balloters	
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	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Hankins - Laura Hankins On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - Laura Hankins	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Standifur - Austin Energy - 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	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 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	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
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	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, 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	
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	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE is concerned the timeframes leave the risk in place for longer than it needs to be. Texas RE requests the standard drafting team's reasoning for the 24 month and 48 month timeframes for completing a CAP.	
Likes 0	
Dislikes 0	
Response	

See the unofficial comment form for additional information: https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_Unofficial_Comment_Form_Initial%20Ballot%20EOP-012-2_June2023.docx

6. Do you agree that Requirement R8 is sufficient to inform the Balancing Authority of the potential impacts a constraint declaration may have on the generating unit's performance to its Extreme Cold Weather Temperature? If you do not agree, or if you do agree but have an alternative approach that will more effectively address the concern, please provide your recommendation and, if appropriate, technical or procedural justification.

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

It is our opinion that only Requirement R8.1 and R8.2 are truly needed. TOP-003-5 R2 already requires the BA to include the operational limitations during local forecasted cold weather in its documented data specification. As the planning entity, the BA needs to know the operational parameters and capabilities of a GO's unit(s). If the BA determines that it also needs additional information (i.e. the Generator Cold Weather Constraint declaration), the BA already has the power to request this information via TOP-003-5. As written, the currently proposed Requirement R8.3 would subject the GO to double jeopardy if they do not provide the Generator Cold Weather Constraint declaration to the BA and the BA also includes this in its documented data specification.

Likes 0	
Dislikes 0	

Response

Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC

Answer	No
Document Name	

Comment

SPP would like the SDT to consider removing the statement in requirement *8.3 Provide the Generator Cold Weather Constraint declaration to the Balancing Authority in the format and at the interval specified by the Balancing Authority*.

SPP has concerns with the proposed statement and recommends removing the statement from R8. Given there is no requirement for the Balancing Authority to do anything with these documents, there is no apparent reliability benefit to the Generator Owner and Generator Operator providing constraint declarations to the Balancing Authority. This requirement is purely administrative.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	No
Document Name	
Comment	

The intent and basis for EOP 11-3 and EOP 12-1 as stated in the technical rationale for modifying EOP 11-2 was to separate the Balancing Authority requirements and the GO requirements. R8 brings the BA back into this standard which goes against the premise already set. We recommend this language requiring the BA to solicit GO data to remain in EOP 11-3 to keep the BA requirements out of EOP 12.

Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

Requirement R8, Part 8.3 stipulates that the declaration be provided to the Balancing Authority "in the format and at the interval sprecified by the Balancing Authority". However, there is no requirement for the BA to specify this and the standard doesn't apply to the BA. If this requirement is to stay this way, section 4.1 needs to include the BA and a requirement needs to be added for the BA to provide the required format and intervals.

Likes 0	
Dislikes 0	
Response	

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt

Answer	No
Document Name	
Comment	

Black Hills Corporation does not agree with the language as TOP-003 and EOP-011 already cover the BA getting their needed information for cold weather generator performance for reliability.

Likes 0	
Dislikes 0	
Response	

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation does not agree with the language as TOP-003 and EOP-011 already cover the BA getting their needed information for cold weather genrator performance for relaibiltiy.	
Likes 0	
Dislikes 0	
Response	

Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Black Hills Corporation does not agree with the language as TOP-003 and EOP-011 already cover the BA getting their needed information for cold weather generator performance for reliability.	
Likes 0	
Dislikes 0	
Response	

Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation does not agree with the language as TOP-003 and EOP-011 already cover the BA getting their needed information for cold weather generator performance for reliability.	
Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	

The SRC agrees that Requirement R8 is a helpful, albeit incomplete, method of informing the Balancing Authority of the nature and existence of a constraint declaration. However, Balancing Authorities would be better informed of the potential impacts of the constraint declaration if Requirement R8, Part 8.3 also required the provision of the operating limitations referenced in Requirement R8, Part 8.2.

The SRC also recommends that Part 8.2 be revised to clarify that operating limitations should be updated at least annually, which would be consistent with Part 8.1.

Finally, the SRC recommends that the drafting team consider expanding Part 8.3 to also require GOs to provide constraint-related information to Reliability Coordinators and Transmission Operators, as information regarding generator availability and operating limitations may inform analysis of thermal, voltage, and stability limits and any associated Operating Plans.

Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	

AES CE believes that R8.3 requires a corresponding requirement in TOP-003 to ensure that BA specifies the format and intervals required for the GO to submit Generator Cold Weather Constraint declarations to them. AES CE has had to struggle with various BAs with the current IRO-010-4 and TOP-003-5 in ensuring that the minimum temperature data (from EOP-011-2) is provided to the BA in the right format as requested. So, without a corresponding requirement in TOP-003 for the BA, R8.3 will not have any reliability impact that FERC wants to address.

Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	No
Document Name	

Comment	
There needs to be a requirement of the Balancing Authority to establish the format and interval that the GO is required to adhere to.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC signed on to ACES comments: It is our opinion that only Requirement R8.1 and R8.2 are truly needed. TOP-003-5 R2 already requires the BA to include the operational limitations during local forecasted cold weather in its documented data specification. As the planning entity, the BA needs to know the operational parameters and capabilities of a GO's unit(s). If the BA determines that it also needs additional information (i.e. the Generator Cold Weather Constraint declaration), the BA already has the power to request this information via TOP-003-5. As written, the currently proposed Requirement R8.3 would subject the GO to double jeopardy if they do not provide the Generator Cold Weather Constraint declaration to the BA and the BA also includes this in its documented data specification.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
Enel North America Inc. does not agree that R8.3 is effective. The Balancing Authority already has the ability to request this information from Generator Owners through Reliability Standard TOP-003. Keeping this data request in EOP-012 creates an administrative requirement instead of one that promotes reliability if the Balancing Authority does not have a plan to request or use the data. See 138 FERC ¶ 61,193, Paraph 81, Criterion B which addresses Reliability Standard requirements that are immaterial to reliability that are "administrative, data collection/data retention; documentation; reporting; periodic updates; commercial or business practice; and redundant," has led to multiple NERC projects and subsequent FERC approval retiring existing requirements that meet these criteria.	
Likes 0	

Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

Ameren agrees with and supports NAGF comments on this question.

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 believes that Requirements 8.1 and 8.2 address providing unit limitations to the BA to address reliability and therefore fully address FERC's concern raised in the order. Requirement 8.3 requires providing extraneous information, i.e. why and under what conditions a Generator Owner made a business decision. This information is not needed by the BA and can only be used to question decisions made by the Generator Owner, not address reliability.

The NAGF notes its concern that overloading entities with information extraneous to their needs makes it hard for the entity to find the pertinent data to allow for them to complete their responsibilities efficiently. Providing business decisions (which as structured may be a single sentence or a multi-page document that includes a root cause analysis, multiple quotes from vendors, etc.) to the Balancing Authority does not address reliability and instead is a documentation issue which has already been deemed immaterial to reliability (see paragraph 81 from the order in Docket RC11-6-000). Requirements 8.1 and 8.2 provides all necessary reliability information related to a declaration without providing information that is not pertinent to the Balancing Authority.

Instead of Requirement 8.3, NERC should have a reporting process for CAPs similar to what it uses for PRC-004. In this manner every CAP would be reported to NERC and these reports could be provided to FERC if FERC so desires. This would allow FERC to see what CAPs are not being completed and for what reason. If the issues are commercial in nature, then FERC can determine how best to address the lack of compensation as currently ordered in relation to this standard. The reports could also be provided to the Balancing Authorities of the reporting entities if the BA wishes to see them. In this manner, the questions related to business decisions would be kept out of a reliability compliance process while being made available to those that desire to evaluate the efforts being made by the Generator Owners.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer	
Answer	No
Document Name	
Comment	
Minnesota Power supports the North American Generator Forum's (NAGF) comments.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
ISO-NE recommends modifying R8.3 to "Provide the Generator Cold Weather Constraint declaration and any updates annually to its **Planning Coordinator**." As currently written R8.3 looks like it is prescribing a requirement for the BAs to provide the GO with the format and interval for the Generator Cold Weather Constraint declaration. The BA is not an Applicable Function of EOP-012-2. TOP-003-2 R2 requires that BAs provide GOs with a data specification including data needed and the periodicity; however, this data is specific to the **Operations Planning Horizon** and **Real-time Monitoring**, while EOP-012-2 R8 is for the **Long Term Planning Horizon**. According to the NERC Reliability Functional Model Technical Document, Balancing Authority does not perform its actions in the **Long Term Planning Horizon**. ISO-NE believes the appropriate function for the **Long-term Planning Horizon** would be the **Planning Coordinator** for this requirement. In addition to the above comment, what was the justifications for the RC or TOP not receiving the constraint declaration since those entities perform Reliability Assessments, including assessments in the Long-term Planning Horizon?	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NV Energy does not agree with the language proposed in R8.3. TOP-003 provides an avenue for the BA to make a request. Also, EOP-012-2 R8.1 already provides a periodicity. Therefore, the statement "... in the format and at the interval specified by the Balancing Authority" is not needed. NV Energy recommends removing 8.3 all together, as it is already sufficiently covered in TOP-003.	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No
Document Name	
Comment	
Buckeye supports the comments by ACES: It is our opinion that only Requirement R8.1 and R8.2 are truly needed. TOP-003-5 R2 already requires the BA to include the operational limitations during local forecasted cold weather in its documented data specification. As the planning entity, the BA needs to know the operational parameters and capabilities of a GO's unit(s). If the BA determines that it also needs additional information (i.e. the Generator Cold Weather Constraint declaration), the BA already has the power to request this information via TOP-003-5. As written, the currently proposed Requirement R8.3 would subject the GO to double jeopardy if they do not provide the Generator Cold Weather Constraint declaration to the BA and the BA also includes this in its documented data specification.	
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	No
Document Name	
Comment	
SMUD and BANC agree with the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Daniel Roethemeyer - Vistra Energy - 5	
Answer	No
Document Name	
Comment	
We agree with the NAGF comments	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	No
Document Name	
Comment	
The burden shoud be placed on the BA, much like any other data requests in other standards. This should not be part of this standard.	
Likes 0	
Dislikes 0	
Response	

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
MRO NSRF does not agree with the language proposed in R8.3. TOP-003 provides an avenue for the BA to make a request. Also, EOP-012-2 R8.1 already provides a periodicity. Therefore, the statement *"... in the format and at the interval specified by the Balancing Authority"* is not needed. MRO NSRF recommends removing 8.3 all together, as it is already sufficiently covered in TOP-003	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State would like to suggest that 8.3 coincide with the 8.1 annual timframe or when updates to the limitations are made under 8.2. 8.3 should have a 90 day schedule as well.	
Likes 0	
Dislikes 0	
Response	

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PGAE agrees and supports the NAGF comments.	
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 supports the NAGFs comments.	
Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	
Comment	

The intent and basis for EOP 11-3 and EOP 12-1 as stated in the technical rational for modifying EOP 11-2 was to separate the Balancing Authority requirements and the GO requirements. R8 brings the BA back into this standard which goes against the premise already set. We recommend this language requiring the BA to solicit GO data to remain in EOP 11-3 to keep the BA requirements out of EOP 12.

Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	No
Document Name	
Comment	

Generator owners communicate this information directly with our Transmission Operators. If the GO is to communicate any constraints it must go through the TOP who is responsible for system load.

Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	
Comment	

Parts 8.1 and 8.2 address providing unit limitations to the BA to address reliability. These address fully FERC's concern raised in the order. Part 8.3 requires providing extraneous

information, i.e. why and under what conditions a Generator Owner made a business decision. This information is not needed by the BA and can only be used to question decisions made by the Generator Owner, not address reliability.

As mentioned by FERC staff during one SDT call, there is concern that overloading entities with information extraneous to their needs makes it hard for the entity to find the pertinent data to allow for them to complete their responsibilities efficiently. Providing business decisions (which as structured may be a single sentence or a multi-page document that includes a root cause analysis, multiple quotes from vendors, etc.) to the Balancing Authority does not address reliability and instead is a documentation issue which has already been deemed immaterial to reliability (see paragraph 81 from the order in

Docket RC11-6-000). Parts 8.1 and 8.2 provides all needed reliability information related to a declaration without providing information that is not pertinent to the Balancing Authority. Instead of Part 8.3, NERC should have a reporting process for CAPs similar to what it uses for PRC-004. In this manner every CAP would be reported to NERC and these reports could be provided to FERC if FERC so desires. This would allow FERC to see what CAPs are not being completed and for what reason. If the issues are commercial in nature, then FERC can determine how best to address the lack of compensation as currently ordered in relation to this standard. The reports could also be provided to the Balancing Authorities of the reporting entities if the BA wishes to see them. In this manner, the questions related to business decisions would be kept out of a reliability compliance process while being made available to those that desire to evaluate the efforts being made by the Generator Owners.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
The intent and basis for EOP 11-3 and EOP 12-1 as stated in the technical rational for modifying EOP 11-2 was to separate the Balancing Authority requirements and the GO requirements. R8 brings the BA back into this standard which goes against the premise already set. We recommend this language requiring the BA to solicit GO data to remain in EOP 11-3 to keep the BA requirements out of EOP 12.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, 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 with the language proposed in R8.3. TOP-003 provides an avenue for the BA to make a request. Also, EOP-012-2 R8.1 already provides a periodicity. Therefore, the statement “... in the format and at the interval specified by the Balancing Authority” is not needed. Tacoma Power recommends that R8.3 is re-worded to the following: *“Provide the Generator Cold Weather Constraint declaration to the Balancing Authority.”*	
Likes 0	
Dislikes 0	

Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	No
Document Name	NAGF EOP-012-2 Comment Form Draft 3.docx
Comment	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Joseph Gatten On Behalf of: Nicholas Friebel, Xcel Energy, Inc., 5, 3, 1; - Joseph Gatten	
Answer	Yes
Document Name	
Comment	
Xcel Energy supports comments offered by EEI in response to question 9 of the comment form.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes

Document Name	
Comment	

Constellation has no additional comments

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6

Answer	Yes
Document Name	
Comment	

Constellation has no additional comments

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC

Answer	Yes
Document Name	
Comment	

PNM agrees that Requirement R8 is sufficient to inform the BA of potential impacts a constraint declaration may have on a generating unit's performance during an Extreme Cold Weather Temperature.

Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	

Comment

AZPS agrees that R8 is sufficient to inform the BA of the potential impacts a constraint declaration may have on the generating unit’s performance to its ECWT.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	Yes
Document Name	

Comment

ITC supports EEI's comments.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6

Answer	Yes
Document Name	

Comment

See comments submitted by Edison Electric Institute

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	
Pamela Hunter - 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 agreeing that R8 is sufficient to inform the BA of potential impacts to a generation unit's performance a constraint declaration may have.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG agrees with NPCC/RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, 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	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 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	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Abbas Munir - Bruce Power - 5 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Standifur - Austin Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Hankins - Laura Hankins On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - Laura Hankins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 3, 1; - Patricia Robertson, Group Name BC Hydro Balloters	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE noticed that Requirement R8 simply requires a declaration to the Balancing Authority (BA). Texas RE recommends the Generator Owner also include justification for the Generator Cold Weather Constraint. Texas RE also recommends making it clear that if the capability and availability require updating, it should be clear that the update does not re-start the periodicity for Requirement R1.	
Likes 0	
Dislikes 0	
Response	

See the unofficial comment form for additional information: https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_Unofficial_Comment_Form_Initial%20Ballot%20EOP-012-2_June2023.docx

7. Per the FERC directive to shorten the timeframe to implement freeze protection measures on existing units, the SDT proposes an implementation plan where all requirements of EOP-012-2 go into effect on the effective date of the standard except Requirement R3 which has a 12-month implementation time frame. The chart below is included to compare the EOP-012-1 and EOP-012-2 IPs for this requirement which requires GOs to have the capability to operate at the ECWT or a CAP written by the effective date of the requirement. If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

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

Answer	No
Document Name	

Comment

Based on the table provided in the comment form, which shows EOP-012-1 and EOP-012-2 as both having a 10/1/2024 effective date, Tacoma Power is concerned that EOP-012-1 and EOP-012-2 will be implemented concurrently. Similar to precedent from the PRC-005 revisions, the EOP-012-2 implementation plan should immediately supersede the EOP-012-1 implementation plan. Since EOP-012-1 may not be effective before EOP-012-2 comes to play, it's more appropriate to supersede rather than "retire" EOP-012-1. For example, here’s the language used for the PRC-005-6 implementation plan: “Because PRC-005-6 incorporates all revisions to date, this implementation plan will supersede the implementation plans for PRC-005-2(ii), PRC-005-3, PRC-005-3(i), PRC-005-3(ii), PRC-005-4 and PRC-005-5 when PRC-005-6 becomes effective. PRC-005-2(i) will remain in effect and not be retired until entities are required to be compliant with R1, R2, and R5 of the PRC-005-6 standard under this implementation plan.” Tacoma Power recommends utilizing similar language in the EOP-012-2 implementation plan to make it clear that entities do not need to concurrently implement both EOP-012-1 and EOP-012-2 at the same time, that the EOP-012-2 implementation plan suipersedes EOP-012-1 (not a retirement), and how the phased implementation Requirements between the two versions should be handled.

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3

Answer	No
Document Name	

Comment

We have been planning for implementation as noted in EOP 12-1. The more aggressive timeframe as provided in EOP 12-1 adds more complexity to our cold weather compliance plans, adds new data and should if anything extend the deadlines, not move them up by 3 years.

Likes 0	
Dislikes 0	

Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
As stated earlier, no timeframe can be developed until EOP-012 is rephased in an understandable manner, especially as regards separating true freezing/congealing (dry bulb temperature and wind) from precipitation. These issues stand separate; a unit protected to -30 F with a 20 mph wind could be knocked offline at 32 F if it has a snow blockage vulnerability.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation does not agree with the new dates suggested for EOP-012-2, and recommends remaining with EOP-012-1 dates as no justification has been provided why they are being shortened.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
We have been planning for implementation as noted in EOP 12-1. The more aggressive timeframe as provided in EOP 12-1 adds more complexity to our cold weather compliance plans, adds new data and should if anything extend the deadlines, not move them up by 3 years.	
Likes 0	
Dislikes 0	

Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PGAE agrees and supports the NAGF comments.	
Likes 0	
Dislikes 0	

Response	
Abbas Munir - Bruce Power - 5 - NPCC	
Answer	No
Document Name	
Comment	
This time frame may not be sufficient to address freeze protection measures for a multi-unit generator facilities hence there should be a provision for MP to work with the balancing authority to develop and agree on a schedule for corrective action implementation.	
Likes 0	
Dislikes 0	

Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	No
Document Name	
Comment	
Smaller entities that have multiple projects need to go through a buget process and need time to implement corrections throughout their fleet. Smaller entites will find this a significant burden.	
Likes 0	
Dislikes 0	

Response	
Daniel Roethemeyer - Vistra Energy - 5	
Answer	No
Document Name	
Comment	
We agree with the NAGF comments	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No
Document Name	
Comment	
Buckeye supports the comments by ACES: While the proposed Implementation Plan timeline for R3 is reasonably feasible for a GO that owns very few units, the proposed schedule is exponentially more difficult for a large GO, especially a GO with a diverse geographic footprint. We recommend a 24-month phased implementation plan for Requirement R3.	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	No
Document Name	
Comment	
IID believes that original Implementation plan should be honored, in order to let entities implement CAPs. Outages for Generation units are limited to winter season.	
Likes 0	

Dislikes 0	

Response

Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer	
Answer	No
Document Name	
Comment	
Minnesota Power supports the North American Generator Forum's (NAGF) comments.	
Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
Based on the current understanding of what the SDT desires, the NAGF believes that this time frame is likely reasonable. However, the issues raised in other comments must be addressed to ensure that industry fully understands what is expected rather than having significant potential issues caused by the lack of clarity in the use of the term freezing and providing a clear design requirement instead of a strictly temperature-based concept that does not provide a reasonable level of reliability.	
Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports NAGF comments on this question.	
Likes 0	

Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	No
Document Name	

Comment

Enel North America Inc. does not agree with the implementation plan time clock starting on 10/1/2024; Enel does not object to the 12 calendar month implementation plan between the effective date of EOP-012-2 and Requirement R3; however, the concern is based on time period between the FERC approval date and the 10/1/2024 effective date of EOP-012-2. If there are considerable delays between the ballot body approval (and assumed standard language changes due to additional ballots), the time frame to become compliant with the final standard language could be considerably shortened. Additionally, Enel supports the NAGF's stance that "no timeframe can be developed until EOP-012 is rephased in an understandable manner, especially as regards separating true freezing/congealing (dry bulb temperature and wind) from precipitation. These issues stand separate; a unit protected to -30 F with a 20 mph wind could be knocked offline at 32 F if it has a snow blockage vulnerability. … The issues raised in other comments must be addressed to ensure that industry fully understands what is expected rather than having significant potential issues caused by the lack of clarity in the use of the term freezing."

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

AEPC signed on to ACES comments:

While the proposed Implementation Plan timeline for R3 is reasonably feasible for a GO that owns very few units, the proposed schedule is exponentially more difficult for a large GO, especially a GO with a diverse geographic footprint. We recommend a 24-month phased implementation plan for Requirement R3.

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	
Comment	
Refer to comments in response to Question 5.	
Likes 0	
Dislikes 0	
Response	
Don Cribb - Santee Cooper - 5, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
This is not enough time to implement these requirements. These time periods should be added to those invoked by EOP-012-1 Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, 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 objections to proposed plan.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	No
Document Name	

Comment	
For the reasons discussed in its response to question 9, the SRC believes that the CAP implementation timelines in R7.1.1 and R7.1.2 should be shortened to 12 months and 24 months, respectively and that the language in both of these parts of Requirement R7 should be clarified.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation is concerned that this could currently be confused with having to comply with both implementation of version EOP-012-1 & EOP-012-2 as stated in the table provided; clarity is needed between the 2 versions for implementation. Additionally, no justification has been provided as to "shortened time frame", which could affect the cost of compliance.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Black Hills Corporation is concerned that this could currently be confused with having to comply with both implementation of version EOP-012-1 & EOP-012-2 as stated in the table provided; clarity is needed between the 2 versions for implementation. Additionally, no justification has been provided as to "shortened time frame", which could affect the cost of compliance.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No

Document Name	
Comment	

Black Hills Corporation is concerned that this could currently be confused with having to comply with both implementation of version EOP-012-1 & EOP-012-2 as stated in the table provided; clarity is needed between the 2 versions for implementation.   Additionally, no justification has been provided as to “shortened time frame”, which could affect the cost of compliance.

Likes 0	
Dislikes 0	
Response	

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt

Answer	No
Document Name	
Comment	

Black Hills Corporation is concerned that this could currently be confused with having to comply with both implementation of version EOP-012-1 & EOP-012-2 as stated in the table provided; clarity is needed between the 2 versions for implementation.   Additionally, no justification has been provided as to “shortened time frame”, which could affect the cost of compliance.

Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1

Answer	No
Document Name	
Comment	

We have been planning for implementation as noted in EOP 12-1. The more aggressive timeframe as provided in EOP 12-2 adds more complexity to our cold weather compliance plans, adds new data and should, if anything, extend the deadlines, not move them up by 3 years.

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	

While the proposed Implementation Plan timeline for R3 is reasonably feasible for a GO that owns very few units, the proposed schedule is exponentially more difficult for a large GO, especially a GO with a diverse geographic footprint. We recommend a 24-month phased implementation plan for Requirement R3.

Likes 0	
Dislikes 0	
Response	

Scott McGough - Georgia System Operations Corporation - 3,4

Answer	No
Document Name	NAGF EOP-012-2 Comment Form Draft 3.docx
Comment	
Likes 0	
Dislikes 0	
Response	

James Keele - Entergy - 3

Answer	Yes
Document Name	
Comment	

EOP-012-1

EOP-012-2

Effective Date

10/1/2024

10/1/2024

Have Capability to Operate at ECWT or CAP Developed

4/1/2028

10/1/2025

CAP Completed

no end date specified

10/1/2027 (R7.1.1) or 10/1/2029 (R7.1.2)

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	Yes
Document Name	

Comment

OPG agrees with NPCC/RSC's comments.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

FirstEnergy supports the proposed timeframe.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment	
WEC Energy Group supports EEIs comments.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - 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 and is not opposed to the implementation deadlines.	
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	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	

The MRO NSRF agrees the shortened timeframe is accurate.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the proposed implementation deadlines.	

Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
NV Energy agrees the shortened timeframe is accurate.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
ISO-NE has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM agrees with the proposed implementation deadlines.	
Likes 0	
Dislikes 0	

Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	

Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	

Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
SIGE does not oppose the proposed implementation deadlines.	
Likes 0	

Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Hankins - Laura Hankins On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - Laura Hankins	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
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 Standifur - Austin Energy - 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	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
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	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Joseph Gatten On Behalf of: Nicholas Friebel, Xcel Energy, Inc., 5, 3, 1; - Joseph Gatten	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 3, 1; - Patricia Robertson, Group Name BC Hydro Balloters	
Answer	
Document Name	
Comment	
Abstain from commenting.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
As stated previously, Texas RE requests justification for the 24 month and 48 month timeframe for completed a CAP.	
Likes 0	
Dislikes 0	
Response	

8. The SDT proposes that the modifications in EOP-012-2 meet the key recommendations in The Report as well as the directives in the FERC order 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.

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

See previous comments for questions 1 and 3.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	No
Document Name	

Comment

Given we are not in support of these changes as written, meeting the key recommendations in The Report in a cost effective manner cannot be determined.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

We believe NERC should strongly consider exempting nuclear powered generating units from EOP-012-2. As a NERC Reliability Guideline (Generating Unit Winter Weather Readiness - Current Industry Practices – Version 3) issued in December 2020 states: "*It is recognized that nuclear power plants, in keeping with NRC regulation and INPO guidance already have more detailed Winterization and Summerization procedures than are expected by this document.*" The nuclear power industry is used to working under NRC regulation and INPO guidance in this area, and adding another layer of NERC requirements (potentially overlapping) adds an extra burden to the site staffs and confusion on what actions are necessary and required. We are not

aware of any significant performance issues with nuclear generating units during the cold weather events that led to development of the EOP-012 standard.

Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
For the reasons outlined in its responses to the other questions in these comments, including, but not limited to, the overly broad and ambiguous definition of a commercial constraint and the inconsistency of footnotes 1, 2, and 4 with FERC's directives, the SRC does not agree that EOP-012-2 as proposed meets the key recommendations in the Report or the directives in the FERC order. The SRC has proposed specific language that would ensure the standard meets its intended goal of enhancing reliability in a cost-effective manner.	
Likes 0	
Dislikes 0	
Response	
Don Cribb - Santee Cooper - 5, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
There are a limited number of vendors and material supplies available to make these changes. The implementation plan length does not take this into account. Implementation for R3 should be spread over 10 years.	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	

AES CE is concerned about the lack of cost analysis being performed. Currently, as written, there is no basis to assume anything but unlimited cost potential with no economic recovery of these costs. AES CE also supports NAGF's comments.

Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
The Standard is not clear for the hydraulic units in the powerhouse. It significantly increases compliance costs.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	No
Document Name	
Comment	

Invenergy is unable to quantify the overall costs and benefits to arrive at a definitive conclusion about the cost effectiveness of the current draft. To determine cost effectiveness, the overall benefit of the proposal must be measured against the overall cost, and neither NERC nor FERC has done that analysis. NERC has written volumes on the expected reliability benefits of the standard, yet it expects generators to spend unlimited sums to comply with the standard without the cost-benefit analysis.

The February 2021 Cold Weather Outages in Texas and the South Central United States (Nov. 2021) (the "Report") recommended that "generating units need to be modified/retrofitted to perform under the adverse winter weather conditions that have been experienced at its location." Report at 188-89. But the Report also emphasized the importance of compensating generators for these retrofits, noting specifically that "Generator Owners should have the opportunity to be compensated for the costs of retrofitting their units to operate to a specified ambient temperature and weather conditions." Report at 191-92. So far, neither NERC, nor FERC (despite numerous asks by industry) has taken any steps to allow for such cost recovery. Invenergy remains concerned that certain generating units, including independent power producers, may be required to bear significant incremental costs to comply with the standard without a corresponding mechanism for recovering those costs.

In addition, the Commercial Constraint provision is so narrowly written that it fails to allow for any cost-benefit analysis. It appears that the only possible Commercial Constraint would be the cost of compliance being greater than the cost of retiring the generation unit. Invenergy suggests a less restrictive Commercial Constraint—not one that would incentivize the avoidance of making a capital improvement—but one that allows for a reasonable cost-benefit analysis of whether the benefit that would result from a prohibitively priced piece of equipment otherwise necessary for compliance is not worth the cost. The current Commercial Constraint provision is clearly unreasonable. For example, if equipment would improve performance during freezing

temperatures by only one (1) degree to be compliant, the GO would have to purchase and install such equipment regardless of its cost, so long as the cost is less than retirement of the unit.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
See previous comments for questions 1 and 3.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
It is difficult for the industry to determine the full cost implications of EOP-012-2. Particulary with the development of Corrective Action Plans as a result of extreme weather, it is premature, to determine at this time, the cost implications until it is fully known what is actually involved.	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	

Invenergy is unable to quantify the overall costs and benefits to arrive at a definitive conclusion about the cost effectiveness of the current draft. To determine cost effectiveness, the overall benefit of the proposal must be measured against the overall cost, and neither NERC nor FERC has done that analysis. NERC has written volumes on the expected reliability benefits of the standard, yet it expects generators to spend unlimited sums to comply with the standard without the cost-benefit analysis.

The *February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 2021) (the "Report") recommended that "generating units need to be modified/retrofitted to perform under the adverse winter weather conditions that have been experienced at its location." Report at 188-89. But the Report also emphasized the importance of compensating generators for these retrofits, noting specifically that "Generator Owners should have the opportunity to be compensated for the costs of retrofitting their units to operate to a specified ambient temperature and weather conditions." Report at 191-92. So far, neither NERC, nor FERC (despite numerous asks by industry) has taken any steps to allow for such cost recovery. Invenergy remains concerned that certain generating units, including independent power producers, may be required to bear significant incremental costs to comply with the standard without a corresponding mechanism for recovering those costs.

In addition, the Commercial Constraint provision is so narrowly written that it fails to allow for any cost-benefit analysis. It appears that the only possible Commercial Constraint would be the cost of compliance being greater than the cost of retiring the generation unit. Invenergy suggests a less restrictive Commercial Constraint—not one that would incentivize the avoidance of making a capital improvement—but one that allows for a reasonable cost-benefit analysis of whether the benefit that would result from a prohibitively priced piece of equipment otherwise necessary for compliance is not worth the cost. The current Commercial Constraint provision is clearly unreasonable. For example, if equipment would improve performance during freezing temperatures by only one (1) degree to be compliant, the GO would have to purchase and install such equipment regardless of its cost, so long as the cost is less than retirement of the unit.

Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

As stated earlier, imposing retrofit obligations, no matter how slight the gain, unless they are so crushingly expensive as to cause a unit to be retired has nothing to do with cost effectiveness. New units should be made to meet the EOP-012-2 design criteria, existing ones should report their dry bulb temperature, DBT + wind and precipitation capabilities (three parameters, not all rolled into one) and GOs should then make commercial decisions regarding retrofitting of units subject to market make-right provisions. If NERC desires to have all units retrofitted, then NERC must address the compensation issue with FERC before a standard can be considered cost-effective. As written, there is no basis to assume anything but unlimited cost potential with no possible economic recovery of these costs.

Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	

The introduction of the term “Generator Cold Weather Critical Component” and “Generator Cold Weather Reliability Event” as currently drafted could have an undue burden and potential cost impact to nuclear generating units to manage and maintain separate lists of components given the conflict between the NERC Standard defined term and the nuclear industry accepted defined term of a “Critical Component”.

Specifically for nuclear generating units “a forced derate of more than 10% of the total capacity of the unit but not less than 20 MWs for longer than four hours in duration” is problematic as it conflicts with the typical scoping and identification of a “Critical Component” that is based on a 20 percent plant transient and therefore nuclear generating units will be challenged with implementing and maintaining two separate criteria for critical components. This will not only be challenging but could also incur additional costs in initially defining and maintaining a component list.

Constellation recommends that the drafting team either align the definition or provide an exemption for nuclear generating units to align with the existing implemented criteria for “Critical Components”.

Additionally, forcing retrofits through CAPs without any market driven compensation will put some GOs at a financial disadvantage with possibly limited reliability benefit to the BES.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer	
Answer	No
Document Name	
Comment	

Minnesota Power supports the North American Generator Forum’s (NAGF) comments.

Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No

Document Name	
Comment	

The introduction of the term “Generator Cold Weather Critical Component” and “Generator Cold Weather Reliability Event” as currently drafted could have an undue burden and potential cost impact to nuclear generating units to manage and maintain separate lists of components given the conflict between the NERC Standard defined term and the nuclear industry accepted defined term of a “Critical Component”. Specifically for nuclear generating units “a forced derate of more than 10% of the total capacity of the unit but not less than 20 MWs for longer than four hours in duration” is problematic as it conflicts with the typical scoping and identification of a “Critical Component” that is based on a 20 percent plant transient and therefore nuclear generating units will be challenged with implementing and maintaining two separate criteria for critical components. This will not only be challenging but could also incur additional costs in initially defining and maintaining a component list. Constellation recommends that the drafting team either align the definition or provide an exemption for nuclear generating units to align with the existing implemented criteria for “Critical Components”. Additionally, forcing retrofits through CAPs without any market driven compensation will put some GOs at a financial disadvantage with possibly limited reliability benefit to the BES.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC

Answer	No
Document Name	
Comment	

PNM has not completed a full assessment of cost at this point so not ready to confirm the cost effectivness of the project.

Likes 0	
Dislikes 0	
Response	

Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group

Answer	No
Document Name	
Comment	

Buckeye supports the comments by ACES:

See previous comments for questions 1 and 3.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	No
Document Name	

Comment

Any additional remediation to retrofit existing units by definition does not correlate with addressing the reliability concerns in a cost effective manner. FERC must address the compensation issue before a standard can be considered for cost-effectiveness.

Likes 0	
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	No
Document Name	

Comment

Any additional remediation to retrofit existing units by definition does not correlate with addressing the reliability concerns in a cost effective manner. FERC must address the compensation issue before a standard can be considered for cost-effectiveness.

Likes 0	
Dislikes 0	

Response

Daniel Roethemeyer - Vistra Energy - 5

Answer	No
Document Name	

Comment

We agree with the NAGF comments

Likes 0	
Dislikes 0	

Response

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1

Answer	No
Document Name	

Comment

This is an incredibly burdensome standard for entities who routinely operate in extreme cold weather. Their operations will not be enhanced, and their reliability will not be improved. Entities like these will be subject to addtional compliance requirements, expense and process. Risk of non-compliance will increase to these entities due to adminstrative errors and a non-defect approach to compliance by auditors.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	No
Document Name	

Comment

PGAE agrees and supports the NAGF comments.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

None.

Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
The changes to EOP-012 address the FERC Order directive, but "cost-effective" is a relative term. This standard will require many GOs to invest additional dollars and customers will bear that burden. If all GO's invest in or shut down their assets, then the market impacts will be distributed across the utilities.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
no.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation does not agree. As annotated above, if there are any upgrades or new equipment installations required, this would create an undue burden on the GO/TO to accomplish this effort in a short amount of time without adding additional costs/manpower efforts.	

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	

Comment
As stated earlier, imposing retrofit obligations, no matter how slight the gain, unless they are so crushingly expensive as to cause a unit to be retired has nothing to do with cost effectiveness. New units should be made to meet the EOP-012-2 design criteria; existing ones should report their dry bulb temperature, DBT + wind, and precipitation capabilities (three parameters, not all rolled into one) and GOs should then make commercial decisions regarding retrofitting of units subject to market make-right provisions. If NERC desires to have all units retrofitted, then NERC must address the compensation issue with FERC before a standard can be considered cost-effective.

Likes 0	
Dislikes 0	

Response

Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	No
Document Name	NAGF EOP-012-2 Comment Form Draft 3.docx

Comment

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
ISO-NE has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG agrees with NPCC/RSC's comments.	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, 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	
Likes 0	
Dislikes 0	
Response	

Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Devon Tremont - Taunton Municipal Lighting Plant - 1	
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	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
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	

Abbas Munir - Bruce Power - 5 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Standifur - Austin Energy - 1	
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	
Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laura Hankins - Laura Hankins On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - Laura Hankins

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Keele - Entergy - 3

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 3, 1; - Patricia Robertson, Group Name BC Hydro Balloters

Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	
Document Name	
Comment	
Black Hills Corporation will not provide comment on cost effectiveness.	
Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
Black Hills Corporation will not provide comment on cost effectiveness.	
Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1	
Answer	
Document Name	
Comment	
Black Hills Corporation will not provide comment on cost effectiveness.	
Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
Black Hills Corporation will not provide comment on cost effectiveness.	
Likes 0	
Dislikes 0	

Response

Joseph Gatten - Joseph Gatten On Behalf of: Nicholas Friebel, Xcel Energy, Inc., 5, 3, 1; - Joseph Gatten	
Answer	
Document Name	
Comment	
Xcel Energy supports comments offered by EEI in response to question 9 of the comments form.	
Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren has no comment on the cost effectiveness of the project.	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
NV Energy abstains from this comment as cost cannot be determined until entities develop CAPs.	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	

Document Name	
Comment	
ITC supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
The MRO NSRF abstains from this comment as cost cannot be determined until entities develop CAPs.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
Southern Company cannot comment on the cost effectiveness of the modifications as this can't be known until after implementation.	
Likes 0	
Dislikes 0	
Response	

9. Provide any additional comments for the standard drafting team to consider, including the provided technical rationale document, if desired.

Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
There are too many changes to cold weather standard too soon. The industry needs to catch up and work on the preious versions before we are ready for incorporating new requirements and obligations in our businesses.	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG agrees with NPCC/RSC's comments and has the following additional comments: i. Considerations should have been given/adopted for generating units that have historically operated in temperatures below 32 degrees Fahrenheit (zero degrees Celsius). ii. EOP-011-02, Requirement 7.3.2 had an “or” between points 7.3.2.1, 7.3.2.2, and 7.3.2.3. When this requirement carried over into EOP-012-02 under Requirement 1.2.2, the “or” was omitted between the corresponding first two points. The “or” should be added again between the first two points. iii. Under the Term Section for “Fixed Fuel Supply Component” of EOP-012-02, please consider including explicit written exception for “water” as a fuel supply to the definition of fuel supply for Hydro. iv. For Requirement R5 under EOP-012-02, suggest instead of annual training, have in place an annual WO (i.e. as the reminder) and Cold Weather Preparedness Training every 3 years.	
Likes 0	
Dislikes 0	
Response	

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	

- R1.2.2 Since the ECWT is calculated with the dry bulb temperature, please provide example of how the concurrent wind and precipitation should be incorporated.
- The first bullet point under R1.2.2 states "Design temperature **and** if available, concurrent wind speed and precipitation." In EOP-011-2, "design temperatures" was followed by an "or". At Idaho Power, only a couple generators available design temperatures. Please give an acceptable option for units that do not have an available design temperature.
- R2 includes the term "self-commits". Please define this.

Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	
Document Name	
Comment	

1. The word "component" in the terms "Generator Cold Weather Critical Component," "Fixed Fuel Supply Component" and their definitions should be changed to, "equipment or systems." The water and steam systems of fossil and combined cycle plants consist of at least hundreds, more likely thousands of components (pipe, tubing, tees, elbows, valves, traps, transmitters, manifolds etc), all protected by a single measure (heat tracing and insulation). Making GOs list them all would be crushingly burdensome, with no BES reliability value whatsoever. The same is true of instrument air systems, which again have a single freeze protection measure (the dryer). We should be allowed to simply declare for example,

"Pump room – close windows before the onset of winter," instead of having to list every item in this room.

Higher granularity is needed at times, though, and EOP-012-2 should require GO/GOPs to focus where the action is, which for conventional generation plants is transmitters that can trip units. A list should be required in this respect, noting that we are once again talking about systems and not components (freezing generally occurs in the impulse lines, not the transmitters themselves). Having to list every pipe run, section of tubing, valve, fitting, door, window, louver etc in the plant would constitute squandering our limited resources. We do support however preparing a list of cold weather critical transmitter systems, so that these key items (including the manifolds and impulse lines) can be prioritized properly out of the innumerable components affected by cold weather. The standard as presently written detracts from BES reliability rather than augmenting it for real-world (i.e. resource-limited) situations, due to not allowing GO/GOPs to prioritize their work.

2. The term, "a specified start-up time," in the Generator Cold Weather Reliability Event definition is excessively vague. What time - to synchronize? To reach the minimum stable load? Full load? A cold start? Warm start? Specified by whom – the plant? The BA/RC/TOP? Specified how – in the IRP-010/TOP-003 data specification? In the MOD-032 report?

It should be changed to, "the startup time agreed-to by the GO/GOP for the extreme cold weather conditions at hand, if more than four hours of delay was caused by genuine freezing of equipment." A GO should not be punished, for example, if a unit capable of starting within eight hours in the summer unexpectedly took twelve and a half hours during a blizzard because the outside operators had to shovel their way through snowdrifts. An extreme cold weather cold-startup time (ECWCST) reported to the Transmission Operator," and GOs should in turn be required to state an ECWCST.

None of the BA/RC/TOPs we deal with currently request such winter vs non-winter information for MOD-032, IRO-010 or TOP-003, and that's part of the problem. A unit with a typical cold-startup time of eight hours might normally need twelve hours when at the ECWT. This is a fact of life, to be taken into account by the TOP when dispatching units, not a threat to BES reliability. One could also ask for at-ECWT hot-startup and warm-startup times, but this would constitute getting over-complicated.

3. R1 should be amended to cover first-time calculation of the ECWT, instead of beginning with criteria for recalculations. Alternatively, make R4 the new R1 (EWCT calculation), pushing the present R1 (recalculation) to the #2 spot.

4. There should be a footnote or Guidance section statement noting that the ECWT calculated for responding to NERC's May 2023 winterization Alert may be used as the first-time identification of this figure for EOP-012 compliance; one doesn't need to make an update upon EOP-012 becoming effective. This material should also state that data may be drawn from any nearby airport. One doesn't need to prove which is the closest, where several such facilities exist. Add also that plant-measured readings are acceptable but not mandatory or even preferred. Our experience is that it is difficult to obtain accurate weather data at a conventional power plant.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	
Document Name	

Comment

There are too many changes to cold weather standard too soon. The industry needs to catch up and work on the preious versions before we are ready for incorporating new requirements and obligations in our businesses.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

None at this time.

Likes 0	

Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
WEC Energy Group supports EEIs additional comments.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
Southern Company supports the EEI comments.	
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	

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PGAE agrees and supports the NAGF comments. PGAE has the following additional comments: The previous draft version has a section 4.2.2 "Exemptions" that has been deleted. PGAE disagrees with the removal of this section. Some generators in the PGAE portfolio have Extreme Cold Weather Temperature higher (warmer) than 32 degrees Fahrenheit. These generator stations do not have specific cold weather equipment or annual maintenance plans or actions taken for cold weather season preparations. These types of Generators need a clearly defined exemption process, such as what was issued for Industry use in EOP-012-1, section 4.2.2. The current exemption notes are unclear of whether or not generating units that have a ECTWS warmer that 32 degrees Fahrenheit are exempt. The notes states in part: Generating unit(s) that do not self-commit or are not required to operate at or below a temperature of 32 degrees Fahrenheit….are exempt. PGAE recommends revising all the notes to state: "Generating unit(s) that do not self-commit, are not required to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius) or have a calculated Extreme Cold Weather Temperature exceeding 32 degrees Fahrenheit (zero degrees Celsius) , but may be called upon to operate in order to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius), are exempt from this requirement".	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Abbas Munir - Bruce Power - 5 - NPCC	
Answer	
Document Name	

Comment	
No further comments	
Likes 0	
Dislikes 0	
Response	

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	

Comment

- The NSRF would like the SDT to consider adding the word "system" to the Generator Cold Weather Critical Equipment definition. The NERC defined term was created in response to the FERC/NERC report Key Recommendation 1a where it recommends that NERC Reliability Standards be revised *"To require Generator Owners to identify cold-weather-critical components and systems for each generating unit. Cold-weather-critical components and systems are those which are susceptible to freezing or otherwise failing due to cold weather, and which could cause the unit to trip, derate, or fail to start."*

In addition to the FERC/NERC report, the *NERC Reliability Guideline – Generating Unit Winter Weather Readiness – Current Industry Practices* also consistently refers to *"…critical components, systems, and other areas of vulnerability which may experience freezing problems or other cold weather operational issues."*

Omitting the word system from the definition could introduce opportunities during CMEP activities to compel entities to provide a list of individual components of systems rather than the systems themselves. This could potentially create an unnecessary administrative burden for registered entities.

One example of the challenge this interpretation could present is in the nuclear industry where INPO AP-913 already defines critical components in a similar manner (See excerpt from INPO AP-913 at the end of this comment) as the proposed terms in EOP-012-2 but with a key difference of a 20% derate threshold in INPO AP-913 versus a 10% in the proposed NERC term. The differing criteria would cause that industry to maintain two separate base lists of critical components where they otherwise could use one and then determine the equipment susceptible to freezing. While changing the criteria in the NERC Generator Cold Weather Reliability Event definition to a 20% derate threshold would alleviate the increased administrative task for the nuclear industry it would still create an additional burden for non-nuclear generation. Using the word "system" would alleviate that interpretation concern and allow entities to focus on the intent of the Standard.

Proposed language for NERC term:*"Generator Cold Weather Critical Component - Any generating unit component, **system** or associated Fixed Fuel Supply Component that is under the Generator Owner's control and is susceptible to freezing issues, the occurrence of which would likely lead to a Generator Cold Weather Reliability Event."*

INPO-913:

"A component shall be classified as critical if a credible single-active component failure will directly result in any of the following unacceptable consequences:

- *reactor scram or turbine trip that will result in a reactor scram (SPV)*
- *significant power transient of greater than 20 percent plant transient (Operational Loss Event)*

- *mitigating system performance indices (MSPI)-monitored component failure*
- *any single failure that causes a complete loss of any of the following critical safety functions*
    - *core, reactor coolant system (RCS) or spent fuel pool (SFP) heat removal*
    - *containment isolation, temperature or pressure*
    - *}reactivity control*
    - *vital alternating current (AC) electrical power*
- *a single equipment failure that results in the complete loss of a Maintenance Rule high-safety-significant or risk-significant function"*

- The MRO NSRF would like the SDT to consider adding clarifying language to R5. The current language allows for interpretation during CMEP activities regarding who should receive the training. The MRO NSRF would like to propose the following language:

"R5. Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s), ***as identified by the responsible entity,*** *developed pursuant to Requirement R4."*

- The MRO NSRF would like the SDT to consider adding clarifying language to R7.4 to better align with the existing proposed language in M7. Because the last sentence in M7 does not correspond fully to language in R7.4 and the Measures are not enforceable, we believe that adding a couple words from M7 to the R7.4 requirement will clarify what documentation is required when claiming a Generator Cold Weather Constraint based on a CAP.

The existing measurement for R7 stipulates "Any declaration shall contain dated documentation to support constraints identified by the Generator Owner". However, R7.4 does not require a dated declaration.

Proposed language for 7.4: *"Document in a* ***dated*** *declaration, with* ***supporting*** *justification, any Generator Cold Weather Constraints that preclude the Generator Owner from implementing actions contained within the Corrective Action Plan."*

- The MRO NSRF is extremely concerned about the method by which the SDT is considering ECWT regarding design requirements and also the method and degree by which cooling due to wind and the effects of precipitation are being considered.

For example, R2.1 requires new units to be able to operate at the unit's ECWT for a period of not less than 12 hours and with a sustained concurrent wind speed of 20 mph. If a unit was to experience conditions of a temperature equal to the ECWT for a period of time equal to 12 hours but with a sustained wind speed of 30 mph, the Generator Owner would be required to perform a CAP if one of the 3 criteria for a Generator Cold Weather Reliability Event was met, regardless of the fact that unit was operating at conditions that exceed the design requirements set forth by THIS standard. There are many other scenarios that could occur where a unit could be found to be deficient as per R6 and require a CAP while operating at conditions that far exceed the severity, in terms of cooling effect or heat loss, which is required by R2 or R3, as applicable.

The MRO NSRF suggests the following change:

Generator Cold Weather Reliability Event - One of the following events for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control *(and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature, REMOVE)* during a period where the facility experienced conditions (including considerations for temperature, duration, and wind speed) that would cause freezing at a rate equal to or at a rate slower than the design conditions set forth by this Standard:

(1) a forced derate of more than 10% of the total capacity of the unit but not less than 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within a specified start-up time;

or

(3) a Forced Outage.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6

Answer	
Document Name	

Comment

See comments submitted by Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1

Answer	
Document Name	

Comment

This proposed standard needs major revisions to assure the compliance burden to smaller utilities who operate traditionally in severe weather are not negatively impacted do to compliance risks and administrative burdens.

Likes 0	

Dislikes 0	

Response

Daniel Roethemeyer - Vistra Energy - 5

Answer	
Document Name	

Comment

We agree with the NAGF comments

Likes 0	
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	
Document Name	

Comment

Regarding the requirements under R4, a generator must develop, implement and maintain a preparedness plan to address identified critical components. However, for generators that experience an Extreme Cold Weather reliability event and a identified critical component (that has been protected) fails resulting in such an event, how would this be handled in the enforcement of the standard? Please explain if this is a violation of the standards.

This standard applies only to generator owners. What about interconnection leads or components that potentially are subject to freezing and can also fail during freeze events? Are these in scope? This is especially impactful for generators that own switchyard equipment.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	
Document Name	

Comment

Regarding the requirements under R4, a generator must develop, implement and maintain a preparedness plan to address identified critical components. However, for generators that experience an Extreme Cold Weather reliability event and a identified critical component (that has been protected) fails resulting in such an event, how would this be handled in the enforcement of the standard? Please explain if this is a violation of the standards.

This standard applies only to generator owners. What about interconnection leads or components that potentially are subject to freezing and can also fail during freeze events? Are these being considered? This is especially impactful for generators that own switchyard equipment.

Likes 0	
Dislikes 0	

Response

Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group

Answer	
Document Name	

Comment

Buckeye supports the following comments made by ACES:

Extreme Cold Weather Temperature: The flexibility and intent behind using the “lowest 0.2 percentile” is greatly appreciated; however, the requirement to use a fixed start date seems a bit excessive. By using a fixed start date, the dataset will grow by 10,824 data points every 5 years when the ECWT is recalculated.
Given the inherent difficulty of compiling a dataset containing greater than 52,000 data points and then calculating the lowest 0.2 percentile, we recommend modifying the definition to remove the requirement to use a fixed data start date of 01/01/2000.
Our proposed modification to the definition would be: “The temperature equal to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from the previous 20 years immediately prior to the date the temperature is calculated. “
R4.1 (footnote 3): By including the stipulation that the GO shall “include the lowest calculated Extreme Cold Weather Temperature for the unit, even where subsequent periodic re-calculations under Requirement R1 Part 1.1 cause an increase in the Extreme Cold Weather Temperature” in a footnote, the SDT is setting the GO up for failure. If it is the intent of the SDT to require the GO to keep records of each ECWT calculation performed by the entity to ensure the lowest value is always captured, then this language should be included in a Requirement and not in the footnotes.

R5: Regarding the proposed verbiage requiring “generating unit-specific training”, it is our opinion that this could be overly burdensome for stations with multiple units; particular for those stations with multiple units of a similar design (a.k.a. “sister” units). Recommend modifying this requirement to require station-specific training in lieu of generating unit-specific training.
It is our opinion that this modification will allow the GO/GOP the flexibility to develop their training modules with an appropriate level of detail to sufficiently train station personnel without requiring them to create multiple modules with similar or identical content.
R6. Concerning the proposed timeline for the development of a CAP, it is our recommendation that the July 1st date be removed from this requirement. The rationale for this recommendations is thus: 150 days prior to July 1st is Feb 1st for non-leap years and Feb 2nd for leap years. Moreover, the July 1st timeline is further condensed if a Generator Cold Weather Reliability Event (GCWRE) occurs in March or April. Lastly, the stated intent of the timeframe options within the Technical Rationale is to allow GOs to review multiple events holistically following a winter season. In certain areas of the country, a GCWRE could realistically occur as early as late-October. In this instance, the latest possible date for the development of a CAP would be March 30th.
Given that it is also realistic for a GCWRE to occur in March, 150 days seems a reasonable number of days to cover all but the most extreme scenarios. Therefore, we recommend removing the hard deadline of July 1st.

Likes 0	
Dislikes 0	

Response	
Stewart Yuen - Nuclear Energy Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

From the attached NEI letter date 7/20/2023:

On behalf of the Nuclear Energy Institute's (NEI){C}[1] members (hereinafter referred to as industry), we provide some comments on Project 2021-07, "Extreme Cold Weather Grid Operations, Preparedness, and Coordination."

The introduction of the term "Critical Component" as currently drafted conflicts with the existing definition used across the nuclear industry and will create unnecessary confusion for nuclear generating units to manage.

In the proposed draft of EOP-012-2 the term "Generator Cold Weather Critical Component" is defined as "[a]ny generating unit component or associated Fixed Fuel Supply Component, that is under the Generator Owner's control, and is susceptible to freezing issues, the occurrence of which would likely lead to a Generator Cold Weather Reliability Event."

A "Generator Cold Weather Reliability Event is further" defined as events "for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature." One of the events listed is:

{C}(1) a forced derate of more than 10% of the total capacity of the unit but not less than 20 MWs for longer than four hours in duration

Specifically for nuclear generating units, "a forced derate of more than 10% of the total capacity of the unit but not less than 20 MWs for longer than four hours in duration" is problematic as it conflicts with the nuclear industry standard definition of a "Critical Component" as defined in industry Equipment Reliability guidance documents. Specifically, the determination of a "critical component" in this context is associated with a credible single-active component failure that will directly result in certain unacceptable consequences. One of those consequences listed is a "significant power transient of greater than 20 percent plant transient (Operational Loss Event)". It should be noted that this includes any single active component failure that causes the 20% derate, so components whose active failure is a result of cold weather would already be considered critical components.

Additionally, since the nuclear industry has implemented the 20% derate criteria to identify critical components as a measure of equipment reliability, the U.S. nuclear fleet overall capability factor has been consistently between 91% and 92.5 % since 2017 which is an industry best benchmark for equipment reliability.

Without revising or aligning the NERC Standard newly defined term of “a forced derate of more than 10%” to the nuclear industry defined term of “greater than a 20 percent plant transient” the nuclear generating units will be burdened with managing two separate criteria for critical components. This would generate confusion and impose an unnecessary burden on the nuclear industry.

NEI recommends that the drafting team either align the NERC Standard definition with the existing and currently implemented criteria under nuclear industry guidance documents or provide an exception for nuclear generating units.

{C}[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.

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

ITC supports EEI's comments.

Likes 0	
Dislikes 0	
Response	
Bret Galbraith - Seminole Electric Cooperative, Inc. - 6	
Answer	
Document Name	
Comment	

1. The SDT’s Extreme Cold Weather Temperature uses a percentile of 0.2. This value consists of a significant digit in the tenth decimal. Using this rationale, when a GO calculates its R1 value, if on year one the GO calculated a temperature of 23.8 F, but then on year 5 the GO recalculated and its subsequent temperature was 23.6 F, it appears that a GO may need to review and update its plans again for a mere 0.2 F change. Please confirm how many significant digits an entity is required to go out to when calculating R1 temperatures.

2. For R1, Seminole suggests a baseline temperature, akin to what NERC has implemented in many PRC Standards, and then a required deviation from that value that would trigger a re-review. For example, if an entity's initial calculation is 10.5 F, then a 5 F decrease is needed in order to set up a new review of all of its cold weather preparedness plans. A review of a GO's plan should not be required for minute decreases in temperature across the board, and if the SDT is afraid of some critical component limit being hit by the lower temperature, a carve out for this concern could be worked into the proposed language that would trigger a re-review.

3. In R2, NERC is using only 2 significant digits when it states "at or below a temperature of 32 degrees F". If an entity calculates its temperature to be 32.5F, Seminole understands that it will round this value up to 33F for R2. Seminole would like clarification from the SDT if the calculated Extreme Cold Weather Temperature value is calculated to 32.4 F, is this value "greater" than 32 F or is it "equal" to 32 F?

Likes 0	
Dislikes 0	

Response

Lindsey Mannion - ReliabilityFirst - 10

Answer	
Document Name	

Comment

RF appreciates the work of the Standard Drafting Team on this project.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	

Comment

NV Eneergy would like the SDT to consider adding the word "system" to the Generator Cold Weather Critical Equipment definition. The NERC defined term was created in response to the FERC/NERC report Key Recommendation 1a where it recommends that NERC Reliability Standards be revised *"To require Generator Owners to identify cold-weather-critical components and systems for each generating unit. Cold-weather-critical components and systems are those which are susceptible to freezing or otherwise failing due to cold weather, and which could cause the unit to trip, derate, or fail to start."*

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Proposed language for NERC term:*"Generator Cold Weather Critical Component - Any generating unit component, **system** or associated Fixed Fuel Supply Component that is under the Generator Owner's control and is susceptible to freezing issues, the occurrence of which would likely lead to a Generator Cold Weather Reliability Event."*

INPO-913:

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significant power transient of greater than 20 percent plant transient (Operational Loss Event)

mitigating system performance indices (MSPI)-monitored component failure

any single failure that causes a complete loss of any of the following critical safety functions:

core, reactor coolant system (RCS) or spent fuel pool (SFP) heat removal

containment isolation, temperature or pressure

reactivity control

vital alternating current (AC) electrical power

a single equipment failure that results in the complete loss of a Maintenance Rule high-safety-significant or risk-significant function"

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"R5. Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s), ***as identified by the responsible entity,*** *developed pursuant to Requirement R4."*

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NV Energy is extremely concerned about the method by which the SDT is considering ECWT regarding design requirements and also the method and degree by which cooling due to wind and the effects of precipitation are being considered.

For example, R2.1 requires new units to be able to operate at the unit's ECWT for a period of not less than 12 hours and with a sustained concurrent wind speed of 20 mph. If a unit was to experience conditions of a temperature equal to the ECWT for a period of time equal to 12 hours but with a sustained wind speed of 30 mph, the Generator Owner would be required to perform a CAP if one of the 3 criteria for a Generator Cold Weather Reliability Event was met, regardless of the fact that unit was operating at conditions that exceed the design requirements set forth by THIS standard. There are many other scenarios that could occur where a unit could be found to be deficient as per R6 and require a CAP while operating at conditions that far exceed the severity, in terms of cooling effect or heat loss, which is required by R2 or R3, as applicable.

NV Energy suggests the following change:

Generator Cold Weather Reliability Event - One of the following events for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control *(**and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature, REMOVE**)* during a period where the facility experienced conditions (including considerations for temperature, duration, and wind speed) that would cause freezing at a rate equal to or at a rate slower than the design conditions set forth by this Standard:

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(2) a start-up failure where the unit fails to synchronize within a specified start-up time;

or

(3) a Forced Outage.

Likes 0	
Dislikes 0	

Response

Diana Torres - Imperial Irrigation District - 6	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	
Document Name	
Comment	

- Considerations should have been given/adopted for generating units that have historically operated in temperatures below 32 degrees Fahrenheit (zero degrees Celsius).
- EOP-011-02, Requirement 7.3.2 had an "or" between points 7.3.2.1, 7.3.2.2, and 7.3.2.3. When this requirement carried over into EOP-012-02 under Requirement 1.2.2, the "or" was omitted between the corresponding first two points. The "or" should be added again between the first two points
- Under the Term Section for "Fixed Fuel Supply Component" of EOP-012-02, please consider including explicit written exception for "water" as a fuel supply to the definition of fuel supply for Hydro.
- For Requirement R5 under EOP-012-02, suggest instead of annual training, have in place an annual WO (i.e. as the reminder) and Cold Weather Preparedness Training every 3 years.

- In the standard (R2 and R3), NERC proposes the threshold of 0°C to determine which groups will or will not be subject to EOP-012. However, for certain entities, it is more the configuration of the power plant (run-of-river vs. reservoir, for example) that dictates the protective measures to be taken than the outside temperatures. Some production groups may not have cold protection measures depending on their configuration (for example an underground power plant with a water intake at the bottom of a reservoir). We urge the standard drafting team to take this into consideration.

- R4 of the standard requires having a preparation plan (or plans) for operation in cold weather and having specific training for each production group on cold protection measures (R5). As cold weather operations are part of our normal operations in the winter in Canada, these elements are already an integral part of our operating frameworks without necessarily being a dedicated document, but rather measures applicable to each plant are incorporated in the operator training program, for example.

- We reiterate that the standard represents an administrative burden for generating units are already regularly called upon during extreme cold weather, such is the case in Canada.

Likes 0	
Dislikes 0	

Response	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	
Document Name	
Comment	

ISO-NE agrees with the SRC that R1 should be revised, so that the ECWT is calculated **annually** and updated in the GO's Cold Weather Preparedness Plan.

ISO-NE also recommends that the GO Cold Weather Preparedness Plan outlined in R4 be moved to R1 and should include all of the currently written R1 as Sub-requirements of the Preparedness plan. This would makes logical sense since the parts of R1 are referenced in the Current R4.1 and 4.2 to be included in the preparedness plan *"as described in R1"* and *"as described in Part 1.2"*.

This would be consistent with the layout of other NERC Standards that require an "Operating Plan" such as EOP-011 R1 and R2 which both state that *"Each TOP/BA shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its TOP/BA Area. The Operating Plan(s) shall include the following, as applicable: ..."*

Suggested Edit:

R1. Each Generator Owner shall develop, maintain, and implement one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: [Violation Risk Factor: High] [Time Horizon: Operations Planning and Real-time Operations]

1.1. The lowest calculated Extreme Cold Weather Temperature for each unit.

1.1.1. Annually, each Generator Owner shall, for each of its applicable generating unit(s):

1.1.1.1. Calculate the Extreme Cold Weather Temperature for each of its applicable generating unit(s) and identify the calculation date and source of temperature data; and

1.1.1.1.1. If the re-calculated Extreme Cold Weather Temperature is lower than the previous Extreme Cold Weather Temperature, the entity shall review and update its cold weather preparedness plan. If new corrective actions are needed to provide the required operational capability under Requirement R2 or R3, the entity shall develop a Corrective Action Plan within six months of the recalculation.

1.2. **Annually,** identify generating unit(s) cold weather data, to include:

1.2.1. Generating unit(s) operating limitations in cold weather to include:

1.2.1.1. Capability and availability;

1.2.1.2. Fuel supply and inventory concerns;

1.2.1.3. Fuel switching capabilities; and

1.2.1.4. Environmental constraints.

1.2.2. Generating unit(s) minimum:

- Design temperature and if available, concurrent wind speed and precipitation;
- Historical operating temperature at least one hour in duration, and if available, concurrent wind speed and precipitation; or

- Current cold weather performance temperature determined by an engineering analysis, which includes concurrent wind speed and precipitation.

1.3. Documentation identifying the Generator Cold Weather Critical Components;

1.4. Documentation of freeze protection measures implemented on Generator Cold Weather Critical Components which may include measures used to reduce the cooling effects of wind determined necessary by the Generator Owner to protect against heat loss, and where applicable, the effects of freezing precipitation (e.g., sleet, snow, ice, and freezing rain); and

1.5. **Annual** inspection and maintenance of generating unit(s) freeze protection measures.

M1. Each Generator Owner will have evidence documenting that its cold weather preparedness plan(s) was implemented and maintained in accordance with Requirement R1. Examples of documentation to demonstrate inspections and maintenance has been completed may include, but are not limited to, completed work order(s) from the Generator Owner's work management system and/or freeze protection checklists identifying the measures inspected and maintained

Likes 0	
Dislikes 0	
Response	

Junji Yamaguchi - Hydro-Quebec (HQ) - 5

Answer	
Document Name	

Comment

Considerations should have been given/adopted for generating units that have historically operated in temperatures below 32 degrees Fahrenheit (zero degrees Celsius).

EOP-011-02, Requirement 7.3.2 had an "or" between points 7.3.2.1, 7.3.2.2, and 7.3.2.3.
When this requirement carried over into EOP-012-02 under Requirement 1.2.2, the "or" was omitted between the corresponding first two points. The "or" should be added again between the first two points.

Under the Term Section for "Fixed Fuel Supply Component" of EOP-012-02, please consider including explicit written exception for "water" as a fuel supply to the definition of fuel supply for Hydro.

For Requirement R5 under EOP-012-02, suggest instead of annual training, have in place an annual WO (i.e. as the reminder) and Cold Weather Preparedness Training every 3 years.

In the standard (R2 and R3), NERC proposes the threshold of 0°C to determine which groups will or will not be subject to EOP-012. However, for certain entities, it is more the configuration of the power plant (run-of-river vs. reservoir, for example) that dictates the protective measures to be taken than the outside temperatures. Some production groups may not have cold protection measures depending on their configuration (for example an underground power plant with a water intake at the bottom of a reservoir). We urge the standard drafting team to take this into consideration.

R4 of the standard requires having a preparation plan (or plans) for operation in cold weather and having specific training for each production group on cold protection measures (R5). As cold weather operations are part of our normal operations in the winter in Canada, these elements are already an integral part of our operating frameworks without necessarily being a dedicated document, but rather measures applicable to each plant are incorporated in the operator training program, for example.

We reiterate that the standard represents an administrative burden for generating units are already regularly called upon during extreme cold weather, such is the case in Canada.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC

Answer	
Document Name	

Comment

PNM supports EEI comments for this question.

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

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We reiterate that the standard represents an administrative burden for generating units that are already regularly called upon during extreme cold weather, such is the case in Canada.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment

Constellation has no additional comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer

Answer	
Document Name	

Comment	
Minnesota Power supports the North American Generator Forum's (NAGF) comments.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
The existing nuclear generator weatherization programs, for both hot and cold weather, developed to comply with NRC regulations and INPO guidance, have been shown to be sufficiently robust to provide reasonable assurance of operation during severe cold weather, e.g., during winter storm Elliott. Given the effectiveness of the existing nuclear programs, and continuing nuclear industry efforts to improve, it is recommended that an exemption be included in EOP-012 for nuclear generators, similar to that in the CIP Standards. Alison Mackellar 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	
Document Name	
Comment	

1. The word “component” in the terms “Generator Cold Weather Critical Component,” “Fixed Fuel Supply Component” and their definitions should be changed to, “equipment or systems.” The water and steam systems of fossil and combined cycle plants consist of at least hundreds, more likely thousands of components (pipe, tubing, tees, elbows, valves, traps, transmitters, manifolds etc.), all protected by a single measure (heat tracing and insulation). Making GOs list them all would be crushingly burdensome, with no BES reliability value whatsoever. The same is true of instrument air systems, which again have a single freeze protection measure (the dryer). We should be allowed to simply declare for example, “Pump room – close windows before the onset of winter,” instead of having to list every item in this room.

Higher granularity is needed at times, though, and EOP-012-2 should require GO/GOPs to focus on critical components, which for conventional generation plants are transmitters that can trip units. A list should be required in this respect, noting that we are once again talking about systems and not components (freezing generally occurs in the impulse lines, not the transmitters themselves). Listing every pipe run, section of tubing, valve, fitting, door, window, louver etc. in the plant however would be an inefficient use of our limited resources. The NAGF does support preparing a list of cold weather critical transmitters, so that these key items (and their manifolds) can be prioritized properly out of the innumerable components affected by cold weather. The standard as presently written detracts from BES reliability rather than augmenting it for real-world (i.e. resource-limited) situations, due to establishing a 300-way tie for priority #1.

2. R1 should be amended to clearly address first-time calculation of the ECWT, instead of beginning with criteria for recalculations. Alternatively, make R4 the new R1 (EWCT calculation), pushing the present R1 (recalculation) to the #2 spot.

3. As written, the information provided under 1.2.2 will at best create unreasonable expectations. A single point in time with a temperature and wind speed does not identify the actual capabilities of a generating unit. A unit that ran at zero degrees and 10 mph wind may easily freeze at that same temperature and wind speed if the temperatures are cold for a longer period leading up to that point. The unit may also have problems if the temperature is warmer but the wind speed is higher. By focusing on dry bulb temperature and then adding wind and precipitation, the SDT will identify a single point upon a wide curve where a unit can operate.

Even worse is concurrent precipitation. It is likely that most if not nearly all units for which the historical operation method is used will report, "X deg. F DBT, concurrent wind speed Y mph, concurrent zero precipitation." How are BAs, RCs and TOPs to make use of reported precipitation rates of zero, other than to conclude as we stated above that accretion and blockage are unrelated to freezing?

We are not adverse to providing data, but GOs being held accountable for others' misinterpretation of our reports is a concern. It appears that the SDT has not yet developed a data specification concept that gives BAs, RCs and TOPs the information they need to accurately predict resource availability for each of the extreme cold weather types:

- Exceptionally cold, little or no wind

- Very cold, high wind (all of the recent generation emergencies that have required shedding firm load have been of this type)

- High precipitation

The SDT probably should not be responsible for creating this type of data specification. However, until NERC pushes these entities to follow recommendations made for at least the last 12 years, it is likely that we will continue to have failures during cold weather events due to a lack of reasonable effort made by the real-time planning entities.

4. The R3 expression, "not capable of operating at its Extreme Cold Weather Temperature," should be clarified for GOs using the historical operation method as being consistent with R1.2.2, "at least one hour in duration." The reason is that the gradual bottoming-out of winter storms causes survival through the nadir to constitute firm proof of capability. The benchmark storm for the PJM is for example, the Polar Vortex of 2014 produced hourly dry bulb temperatures at Allentown, Pa of 7, 6, 4, 4, 2, 1, 0, 0, -1, 1, 2, 3, 4, 5 degrees F. It is obvious that the lengthy, gradual lead-in is sufficient to support a claimed capability of -1 F.

As currently written, it is unclear if an entity with the ECWT above 32 degrees can comply with Requirements R4 and R5. As written, the entity will be unable to identify any generator Cold Weather Critical Components, therefore they will be unable to identify any freeze protection measures and the annual maintenance of those measures. For training, there will be no one to train. This is caused by the very specific requirement to address GCWCC developed in R4. For a unit with an ECWT above 32 degrees, these devices do not exist. The question that needs addressed by the SDT is "Does a unit with an ECWT above 32 degrees need a plan that addresses items that are not listed as required to be included?" The NAGF notes that this issue did not exist under EOP-012-1 or EOP-011-2 due to the different language used related to freeze protection measure (no limitation for GCWCC) or the exclusion of entities that did not operate at low temperatures. While the SDT has done a commendable job to address the issues identified by FERC in the order approving EOP-012-1, the SDT needs to further modify the proposed standard to clarify how an entity with an ECWT is expect to meet the training requirement when there is nothing to be trained on.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	
Document Name	
Comment	

In calculating the Extreme Cold Weather Temperature (ECWT) at multiple facilities so far, Invenergy has, in some cases, been unable to obtain sufficient hourly temperature data coverage back to 1/1/2000, using the methodology NERC set forth in *Calculating Extreme Cold Weather Temperature* (Sept. 2022) using NOAA's climate data tool. For example, there were multiple instances of 5-years of missing hourly data for the closest, most reasonable location for a facility. Invenergy supplemented its ECWT calculations with the next nearest available temperature data, which was sometimes hundreds of miles away from the facility's location. Temperatures that are hundreds of miles away from a location can be drastically different than those at the site, thus skewing the ECWT. Invenergy recognizes that the Technical Rationale document states "If reliable data is not available at a single weather station back to January 1, 2000, the GO should document the methodology they use to determine their ECWT such as appending data from multiple weather stations or selecting a complete data set from a weather station further away from the facility." However, given the frequency of unreliable or insufficient data available in the sources that NERC has suggested, it would be helpful to have further guidance on best practices for calculating a facility's ECWT to avoid having to utilize hourly temperatures for areas far distant from a facility, or alternative methodologies from those presented in *Calculating Extreme Cold Weather Temperature* (Sept. 2022).

Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 3

Answer	
Document Name	
Comment	

Ameren agrees with and supports NAGF comments on this question.

Likes 0	
Dislikes 0	
Response	

Joseph Gatten - Joseph Gatten On Behalf of: Nicholas Friebel, Xcel Energy, Inc., 5, 3, 1; - Joseph Gatten

Answer	
Document Name	
Comment	

Xcel Energy supports comments offered by EEI in response to this question.

Likes 0	

Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster

Answer	
Document Name	

Comment

Evergy asks the SDT to consider making some non-substantive changes to Requirement R7, subpart 7.4 in order to clarify what is required when claiming a Generator Cold Weather Constraint based on a CAP. Evergy believes that the Measures for R7 indicates specific requirements that the drafting team believed a constraint declaration should include and we are proposing to add that language to the acutal requirement so it is enforceable versus only appearing in an uneforcable measure. (Proposed changes in boldface below)

R7. Each Generator Owner, for each Corrective Action Plan developed pursuant to Requirements R1, R2, R3, or R6, shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.4 Document in a **dated** declaration, with **supporting** justification, any Generator Cold Weather Constraints that preclude the Generator Owner from implementing actions contained within the Corrective Action Plan.

M7. Each Generator Owner shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables, or has explained in a declaration why corrective actions are not being implemented in accordance with Requirement R8. Acceptable evidence may include, but is not limited to, the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records. **Any declaration shall contain dated documentation to support constraints identified by the Generator Owner.**

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	
Document Name	

Comment

Enel North America Inc. would like the SDT to also consider the impacts of a NERC Reliability Standard where there are regulatory requirements in overlapping jurisdictions. For example, the Public Utility Commission of Texas has a regulatory requirement (16 TAC 25.55) for cold weather preparations including implementing weather emergency preparations measures to reasonably ensure sustained operation of the resource at the 95th percentile minimum average 72-hour wind chill temperature as reported in the ERCOT historical weather study (16 TAC 25.55(c)(1)(B)). Regional variances should be considered by the SDT where conflicting and similar regulations exist.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

AEPC signed on to ACES comments:

Extreme Cold Weather Temperature: The flexibility and intent behind using the “lowest 0.2 percentile” is greatly appreciated; however, the requirement to use a fixed start date seems a bit excessive. By using a fixed start date, the dataset will grow by 10,824 data points every 5 years when the ECWT is recalculated.

Given the inherent difficulty of compiling a dataset containing greater than 52,000 data points and then calculating the lowest 0.2 percentile, we recommend modifying the definition to remove the requirement to use a fixed data start date of 01/01/2000.

Our proposed modification to the definition would be: “The temperature equal to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from the previous 20 years immediately prior to the date the temperature is calculated. “

R4.1 (footnote 3): By including the stipulation that the GO shall “include the lowest calculated Extreme Cold Weather Temperature for the unit, even where subsequent periodic re-calculations under Requirement R1 Part 1.1 cause an increase in the Extreme Cold Weather Temperature” in a footnote, the SDT is setting the GO up for failure. If it is the intent of the SDT to require the GO to keep records of each ECWT calculation performed by the entity to ensure the lowest value is always captured, then this language should be included in a Requirement and not in the footnotes.

R5: Regarding the proposed verbiage requiring “generating unit-specific training”, it is our opinion that this could be overly burdensome for stations with multiple units; particular for those stations with multiple units of a similar design (a.k.a. “sister” units). Recommend modifying this requirement to require station-specific training in lieu of generating unit-specific training.

It is our opinion that this modification will allow the GO/GOP the flexibility to develop their training modules with an appropriate level of detail to sufficiently train station personnel without requiring them to create multiple modules with similar or identical content.

R6. Concerning the proposed timeline for the development of a CAP, it is our recommendation that the July 1st date be removed from this requirement. The rationale for this recommendations is thus: 150 days prior to July 1st is Feb 1st for non-leap years and Feb 2nd for leap years. Moreover, the July 1st timeline is further condensed if a Generator Cold Weather Reliability Event (GCWRE) occurs in March or April. Lastly, the stated intent of the timeframe options within the Technical Rationale is to allow GOs to review multiple events holistically following a winter season. In certain areas of the country, a GCWRE could realistically occur as early as late-October. In this instance, the latest possible date for the development of a CAP would be March 30th.

Given that it is also realistic for a GCWRE to occur in March, 150 days seems a reasonable number of days to cover all but the most extreme scenarios. Therefore, we recommend removing the hard deadline of July 1st.

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5,6

Answer	
Document Name	

Comment

In calculating the Extreme Cold Weather Temperature (ECWT) at multiple facilities so far, Invenergy has, in some cases, been unable to obtain sufficient hourly temperature data coverage back to 1/1/2000, using the methodology NERC set forth in Calculating Extreme Cold Weather Temperature (Sept. 2022) using NOAA's climate data tool. For example, there were multiple instances of 5-years of missing hourly data for the closest, most reasonable location for a facility. Invenergy supplemented its ECWT calculations with the next nearest available temperature data, which was sometimes hundreds of miles away from the facility's location. Temperatures that are hundreds of miles away from a location can be drastically different than those at the site, thus skewing the ECWT. Invenergy recognizes that the Technical Rationale document states "If reliable data is not available at a single weather station back to January 1, 2000, the GO should document the methodology they use to determine their ECWT such as appending data from multiple weather stations or selecting a complete data set from a weather station further away from the facility." However, given the frequency of unreliable or insufficient data available in the sources that NERC has suggested, it would be helpful to have further guidance on best practices for calculating a facility's ECWT to avoid having to utilize hourly temperatures for areas far distant from a facility, or alternative methodologies from those presented in Calculating Extreme Cold Weather Temperature (Sept. 2022).

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

EEI offers the following comments for consideration:

EEI has concerns with the proposed CAP criteria language in EOP-012-2. The current CAP criteria could be understood to require performance that exceeds the specifications in EOP-002-2 and should be clarified. While it is reasonable to require Generator Owners to reconsider and re-calculate their Extreme Cold Weather Temperature (ECWT) at the proposed intervals, it is not reasonable to expect that GOs can financially sustain the burdens of endless CAPs associated with Generator Cold Weather Reliability Event that exceed the defined criteria due to extended periods of sustained cooling. For example, systems designed to the specified design criteria, conforming to the defined ECWT, specified duration and associated cooling effects of the defined wind speed, may ultimately trip offline even in instances where the temperature has risen above the ECWT after the 12 hour design criteria but due to the duration of the event the system ultimately fails. This does not mean that the mitigations were faulty, the criteria was not met, or a CAP is needed. Rather, the long term conditions that the resource was subjected to exceeded the specification. Moreover, units could conceivably experience additional extreme events that could result in additional Generator Cold Weather Reliability Event before even completing the CAP for the previous event. Without addressing this issue, GOs will be faced with a situation that could result in endless CAPs, creating disincentives to building needed new generation and potentially increase early retirement of resources. To address this concern, we offer the following proposed changes to the Generator Cold Weather Reliability Event (changes in boldface):

Generator Cold Weather Reliability Event - One of the following events for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control **that conforms to the design conditions as set forth in this Standard (i.e., wind and temperature):**

(1) a forced derate of more than 10% of the total capacity of the unit but not less than 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within a specified start-up time;

or

(3) a Forced Outage.

If one or more of the these three (3) events occurs after more than 12 continuous hours of operation, demonstrating generator performance at or exceeding the design conditions as set forth in this Standard, it shall not be considered a Generator Cold Weather Reliability Event.

Generator Cold Weather Constraints: EEI understands that many of our member companies have concerns regarding how to effectively utilize the defined constraints due to the language as currently written.

EEI is concerned that Requirement R5 is not specific enough and could create potential compliance risks for entities that employ OEM contractors to support certain maintenance and/or operations activities. Given these contractors are often not dedicated contract personnel but are deployed on-demand and often represent a very large pool of personnel not under the direct control of the responsible Generator Operator, training of those contractors is often impractical. To address this concern, EEI offers the following proposed changes to Requirement R5 (changes in boldface):

Each Generator Operator or Generator Owner will have documented evidence that the applicable **Generator Operator and/or Generator Owner personnel staff and/or dedicated on-site full time contractors** completed annual training of the Generator Owner's cold weather preparedness plan(s). This evidence may include, but is not limited to, documents such as personnel training records, training materials, date of training, agendas or learning objectives, attendance at pre-work briefings, review of work order tasks, tailboards, attendance logs for classroom training, and completion records for computer-based training in fulfillment of Requirement R5. **On demand contractors used for emergency services, not normally on site, are exempt from this training requirement.**

EEI asks that the SDT support the proposed changes to EOP-012-2 with Implementation Guidance. During both NERC webinars and EEI meetings with its members and the Project 2021-07 Standards Drafting Team, it was clear that many concerns, once explained, were found to be generally acceptable. For this reason, a broader sharing and expounding of SDT insights on the proposed changes may better ensure broader Industry acceptance of the proposed changes.

EEI also asks the SDT to consider making some non-substantive changes to Requirement R7, subpart 7.4 in order to clarify what is required when claiming a Generator Cold Weather Constraint based on a CAP. (Proposed changes in boldface below)

R7. Each Generator Owner, for each Corrective Action Plan developed pursuant to Requirements R1, R2, R3, or R6, shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.4 Document in a **dated** declaration, with **supporting** justification, any Generator Cold Weather Constraints that preclude the Generator Owner from implementing actions contained within the Corrective Action Plan.

M7. Each Generator Owner shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables, or has explained in a declaration why corrective actions are not being implemented in accordance with Requirement R8. Acceptable evidence may include, but is not limited to, the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records. Any declaration shall contain dated documentation to support constraints identified by the Generator Owner.

Likes 0	
Dislikes 0	
Response	

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	
Document Name	
Comment	

If a generating unit is located inside the powerhouse, and the powerhouse is heated in winter, will the generating unit components be considered as Generator Cold Weather Critical Components?

For example, the unit's Extreme Cold Weather Temperature is -40 degrees Fahrenheit (-40 degrees Celsius). However, the unit is located in the powerhouse that is heated to 68 degrees Fahrenheit (20 degrees Celsius) in winter. Will the generating unit components be considered as Generator Cold Weather Critical Components? Will Requirements R2 and R3 be applicable to this unit?

Requirement R4.4 is not applicable if the unit is inside the powerhouse.

Likes 0	
Dislikes 0	
Response	

Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	
Comment	

AES CE strongly recommends the drafting team to consider creating an implementation guidance or a CMEP Practice Guide to ensure consistency in approaches to meeting the new standard and requirements. Additionally, AES CE recommends that the drafting team make necessary corresponding changes for the BA to ensure that they have to perform their part in requesting the necessary data and utilizing the data to perform reliability assessments.

AES CE also would like to request that the drafting team provide clarifications (through Technical Rationale) on whether wind repowering projects that will reach COD after 10/1/2027 are considered new projects.

AES CE has concerns with the proposed CAP criteria language in EOP-012-2. The current proposed CAP process imposes a significant burden (both financially and operationally) to entities. It is not reasonable to expect that GOs can sustain the burdens of endless CAPs associated with Generator Cold Weather Reliability Event that exceed the defined criteria due to extended periods of sustained cooling. For example, systems designed to the specified design criteria, conforming to the defined ECWT, specified duration and associated cooling effects of the defined wind speed, may ultimately trip offline even in instances where the temperature has risen above the ECWT after the 12 hour design criteria but due to the duration of the event the system ultimately fails. This does not mean that the mitigations were faulty, the criteria was not met, or a CAP is needed. Rather, the long term conditions that the resource was subjected to exceeded the specification. Moreover, units could conceivably experience additional extreme events that could result in additional Generator Cold Weather Reliability Event before even completing the CAP for the previous event. Without addressing this issue, GOs will be faced with a situation that could result in endless CAPs, creating disincentives to building needed new generation and potentially increase early retirement of resources.

Additionally, AES CE is concerned that Requirement R5 is not specific enough and could create potential compliance risks for entities that employ OEM contractors to support certain maintenance and/or operations activities. Given these contractors are often not dedicated contract personnel but are deployed on-demand and often represent a very large pool of personnel not under the direct control of the responsible Generator Operator, training of those contractors is often impractical. AES CE proposes either explicitly exclude non-dedicated on-site contractors in the requirement language or provide guidance (in Implementation Guidance) that non-dedicated on-site contractors are excluded.

Likes 0	
Dislikes 0	
Response	
Don Cribb - Santee Cooper - 5, Group Name Santee Cooper	
Answer	
Document Name	
Comment	

Measure M3 lists only a single example of acceptable evidence and does not say that there are alternative evidence measures, just previous operating time below the ECWT.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	

Comment

Texas RE seeks clarity on the first provision in the definition of Generator Cold Weather Reliability Event. Does this provision refer to a total of 20 MW or greater for 4 hours? Will this be cumulative? For example, if a 50 MW unit derates by 15% of its capacity during the last hour of the 4 hours duration, will it be acceptable?

Texas RE is concerned this provision could be misinterpreted to assume that as long as the capacity reduction for each of the 4 hour duration is less than 20 MW, there's no compliance issues. This could exclude all generators rated 199MW or lower. Is that the SDT's intent?

Texas RE understands that Requirements R2 and R3 indicate that if an entity does not self-commit, it does not need to have freeze protection measures. Texas RE is concerned this could lead to an unintended consequence of entities choosing to not self-commit and simply awaiting a directive to deploy. This could lead to artificial capacity shortfalls driven solely by compliance considerations. Texas RE requests that the SDT clarify the language in Requirements R2 and R3 to avoid this possible result.

Likes 0	
Dislikes 0	

Response

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	
Document Name	

Comment

SIGE supports Edison Electric Institute's recommendation for the Standard Drafting Team to develop Implementation Guidance.

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	

The SRC provides the following additional comments for the drafting team to consider.

Revise Requirements R2, R3, and R6 to Better Align with FERC's Mandate and Provide Additional Clarity

The SRC does not read Requirements R2, R3, and R6 to satisfy FERC's mandate that the standard's applicability "exclude only those generation resources not relied upon during freezing conditions." In footnotes 1, 2, and 4 the proposed standard explicitly exempts many units that might run only during emergency conditions. By definition, those units would be "relied upon during freezing conditions," and under the language of the FERC mandate, should be required to meet the standard's requirements. **The SRC recommends removing these footnotes.** The SRC further suggests revising "self-commits or that is required to operate" in R2, R3, and R6 to read "that may be committed to operate" to avoid ambiguity about whether a unit that is available to run but that has not run since the effective date of the standard would be required to meet the requirements of R2, R3, and R6.

Clarify the Definition of Generator Cold Weather Reliability Event

The SRC is concerned that the proposed definition of Generator Cold Weather Reliability Event is ambiguous and does not capture all cold weather reliability events that should be addressed under EOP-012.

First, the SRC is concerned that the four-hour duration threshold in paragraph (1) of the proposed definition will mask a situation where a generating unit repeatedly starts and trips offline or starts and significantly ramps its output up and down within a four-hour period due to inadequate weatherization. During an extreme cold weather event, the inability of a generating unit to reliably **sustain** its output level for a long duration of time is highly detrimental to the overall stability of the BES. However, the four-hour threshold in paragraph (1) would inadvertently create an unreasonably large safe harbor for units that are unable to run consistently or maintain a consistent output due to a failure to properly weatherize. To address this issue, the SRC recommends that paragraph (1) be revised to read as follows: "a forced derate of more than 10% of the total capacity of the unit, but not less than 20 MW, for 30 minutes or more in duration three or more times during the winter season."

Second, the phrase "specified start-up time" in paragraph (2) of the proposed definition does not provide any consistency in how the start-up time is to be applied by individual resources. To address this issue, the SRC recommends that paragraph (2) be revised to provide that a start-up failure consists of a failure to start after one or more attempts.

Confirm that Generator Cold Weather Constraint Declarations are Intended to be Used Infrequently

It is the SRC's understanding that Generator Cold Weather Constraint declarations are intended to be a seldom-used tool rather than a commonly adopted compliance measure. The SRC recommends that this expectation be memorialized in EOP-012 if possible or in the technical rationale for EOP-012, similar to the way that the Guidelines and Technical Basis for PRC-004-6 indicate that "a declaration that no further corrective actions will be taken is expected to be used sparingly."

Monitor the Effectiveness of the ECWT Calculation on Cold Weather Performance

As the ECWT determines the level at which freeze protection measures must be implemented, the effectiveness of EOP-012 at reducing reliability risk associated with extreme cold weather is tied to this determination. The SRC requests NERC monitor the effectiveness of the ECWT calculation by requiring GOs to report their ECWT calculations to NERC annually. Additionally, the SRC recommends that EOP-012 provide as much specificity and standardization as possible regarding how the ECWT is to be calculated and which data sources should be used for the calculations. This will help ensure consistency in how ECWTs are calculated and in the data that is used for the calculations. It will also increase the auditability of ECWT calculations.

The SRC remains concerned that the ECWT as currently defined results in a temperature that does not adequately capture extreme cold weather temperatures and other freeze-related conditions, such as wind chill and precipitation, that a generating resource will need to address in its freeze protection measures. The SRC's proposals in its responses to questions 2 and 3 of this comment form are intended to help address this concern.

As the ECWT sets the temperature at or above which generating units must be capable of operating to avoid having to add new or modify existing freeze protection measures under EOP-012, the SRC is concerned that opportunities to improve unit reliability and weatherization effectiveness will be missed due to the clemency in temperature at which GOs will be required to perform or develop a CAP. Past extreme cold weather events have included a substantial number of hours when the dry bulb temperature was below the ECWT. The SRC simply seeks to ensure that GOs, the ERO, and equipment manufacturers are provided with the data and transparency necessary to take full advantage of the lessons that can be learned from evaluating and analyzing performance issues at temperatures below the ECWT. This information would be useful to other GOs and to FERC and the ERO as they monitor whether this standard effectively accomplishes the reliability goals set forth in the Winter Storm Uri report. Imposing the monitoring and reporting requirements recommended by the SRC will provide the information needed to evaluate the effectiveness of the ECWT and provide an indicator as to when and if any future revisions to the ECWT calculation need to be made.

Revise Requirement R1 to Require Calculation of the ECWT Annually instead of Every Five Years

In order to ensure that the information relied upon to prepare generating units for extreme cold weather remains up to date, the SRC proposes that Requirement R1 be revised to require that the ECWT be calculated at least annually rather than every five years. Once the GO has established a calculation process, it should be fairly straightforward to update the calculations every year. Requiring the GO to calculate the ECWT only once every five years dramatically extends the amount of time it will take to realize incremental reliability improvements that may result from changes in the ECWT, as it could be as long as five years plus the amount of time needed to implement the associated CAP before an incremental reliability improvement is discovered and implemented.

Clarify Ambiguities in Requirement R1

The language proposed in Requirement R1, Part 1.1.1 would require a GO to develop a CAP when an update to the ECWT indicates that a unit would not be able to comply with R2 or R3. It is unclear whether this is intended to be separate from the CAPs that R2 and R3 contemplate. The SRC recommends that Part 1.1.1 be clarified to either specify how the CAP referenced in Part 1.1.1 differs from the R2 and R3 CAPs and the effect that the Part 1.1.1 CAP has on an entity's obligations under the standard, or to specify that Part 1.1.1 sets a deadline for the development of CAPs under R2 and R3 rather than referring to a separate CAP.

R1, Part 1.2.2 requires a GO to identify its "[g]enerating unit minimum . . . current cold weather performance temperature." The purpose of the word "current" in this phrase is unclear. The SRC suggests striking that word.

Revise Requirement R4 to Require More Frequent Inspection and Maintenance Activity

The SRC recommends that Requirement R4, Part 4.5 be revised to require inspections and maintenance to occur immediately prior to and monthly during the winter months in order to ensure that freeze protection measures are inspected at the times when they are most likely to be relied upon.

Clarify Requirement R7 and Shorten Timelines for CAP Implementation

The SRC also proposes to further clarify the language regarding CAPs in Requirement R7. As proposed, the SRC reads Part 7.1.1 to require a GO to "[s]pecify action(s) that address(es) existing equipment or freeze protection measures" and to implement those within 24 months, while Part 7.1.2 requires a GO to "[s]pecify action(s) that require(s) new equipment or freeze protection measures" and implement those within 48 months. However, because some corrective actions may address existing equipment and also require new measures, these categories are not necessarily mutually exclusive, and an ambiguity could therefore arise regarding the appropriate timeline that would apply in such a case. The SRC presumes that the CAP implementation timeline should depend on whether new equipment is required to be installed, and not on whether the CAP "addresses" existing equipment or measures. Regarding the timeline, new "measures" that don't require new equipment would not seem to require more than a year to complete, while new equipment should not require more than two years in the vast majority of cases. Therefore, the proposed 24- and 48-month timelines seem excessive.

The SRC suggests the following revised language for R7, Parts 7.1.1 and 7.1.2:

7.1.1 Specify each corrective action that does not require the installation of new equipment, which actions must be completed within 12 months of development of the Corrective Action Plan; and

7.1.2 Specify each corrective action that requires the installation of new equipment, which actions must be completed within 24 months of development of the Corrective Action Plan.

To help further ensure that CAP updates under R7, Part 7.3 are not overused, the SRC also recommends that Part 7.3 be revised to clarify that the standard of review for a CAP update is whether the update has a reasonable justification. The SRC recommends that Part 7.3 be revised to read as follows: "Update the Corrective Action Plan, with justification, if corrective action(s) reasonably change or timetable(s) reasonably require the GO to exceed the timelines in Part 7.1."

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

For the “Fixed Fuel Supply Component” definition, we suggest adding additional wording (see below). Nuclear Plants have diesel fuel that is not needed for or related to providing power to the generating unit. It is safety related, and not a BES component.

“Fixed Fuel Supply Component - Non-mobile equipment that supports the reliable delivery of fuel to the generating unit ***for the purpose of generating power*** *and under the control of the Generator Owner at a plant site. Gaseous, liquid, or solid fuel handling components that are installed on site as fixed parts of the fuel delivery system that are under the Generator Owner’s control are included. Mobile equipment such as trains, bulldozers, or other equipment that are not fixed in one location are excluded.”*

For Requrement R1:

- We suggest making the frequency every five calendar years to provide some flexibility to the GOs.

- More clarity is needed regarding the recalculation of ECWT every five years. Should each recalculation factor in data back to 1/1/2000, or just the five year period prior to the recalculation?

- Six months is not sufficient time after the recalculation to update a cold weather preparedness plan or develop a Corrective Action Plan for a nuclear plant site due to the level of reviews involved. We suggest a 12 month period.

For Requirement R3:

The revision to Requirement R3 (existing generation) has removed the time constraint. Instead of stating that the plant must be able to operate at ECWT for at least an hour, it now states that if unable to operate at ECWT a CAP must be created. It is very likely that some existing generation will not be able to continuously operate at ECWT no matter what upgrades are performed on them. Usually standards are sticter for newer sites, but if a new site must be able to operate for at least 12 hours at ECWT but an existing site has no limit, the requirement is stricter for existing units.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	
Document Name	

Comment

There are too many changes to this cold weather standard too soon. The industry needs to catch up and work on the preious versions before we are ready for incorporating new requirements and obligations in our businesses.

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	

Extreme Cold Weather Temperature: The flexibility and intent behind using the “lowest 0.2 percentile” is greatly appreciated; however, the requirement to use a fixed start date seems a bit excessive. By using a fixed start date, the data set will grow by 10,824 data points every 5 years when the ECWT is recalculated.

Given the inherent difficulty of compiling a data set containing greater than 52,000 data points and then calculating the lowest 0.2 percentile, we recommend modifying the definition to remove the requirement to use a fixed data start date of 01/01/2000.

Our proposed modification to the definition would be: “The temperature equal to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from the previous 20 years immediately prior to the date the temperature is calculated. “

R4.1 (footnote 3): By including the stipulation that the GO shall “include the lowest calculated Extreme Cold Weather Temperature for the unit, even where subsequent periodic re-calculations under Requirement R1 Part 1.1 cause an increase in the Extreme Cold Weather Temperature” in a footnote, the SDT is setting the GO up for failure. If it is the intent of the SDT to require the GO to keep records of each ECWT calculation performed by the entity to ensure the lowest value is always captured, then this language should be included in a Requirement and not in the footnotes.

R5: Regarding the proposed verbiage requiring “generating unit-specific training”, it is our opinion that this could be overly burdensome for stations with multiple units; particular for those stations with multiple units of a similar design (a.k.a. “sister” units). Recommend modifying this requirement to require station-specific training in lieu of generating unit-specific training.

It is our opinion that this modification will allow the GO/GOP the flexibility to develop their training modules with an appropriate level of detail to sufficiently train station personnel without requiring them to create multiple modules with similar or identical content.

R6. Concerning the proposed timeline for the development of a CAP, it is our recommendation that the July 1st date be removed from this requirement. The rationale for this recommendations is thus: 150 days prior to July 1st is Feb 1st for non-leap years and Feb 2nd for leap years. Moreover, the July 1st timeline is further condensed if a Generator Cold Weather Reliability Event (GCWRE) occurs in March or April. Lastly, the stated intent of the timeframe options within the Technical Rationale is to allow GOs to review multiple events holistically following a winter season. In certain areas of the country, a GCWRE could realistically occur as early as late-October. In this instance, the latest possible date for the development of a CAP would be March 30th.

Given that it is also realistic for a GCWRE to occur in March, 150 days seems a reasonable number of days to cover all but the most extreme scenarios. Therefore, we recommend removing the hard deadline of July 1st.

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6

Answer	
Document Name	
Comment	

During the last presentation NERC stated that “Water” at a hydro facility is not considered fuel, however, previous presentations included water as fuel, this should be clearer as to what is considered fuel for renewable sources or exclude renewables from the clause. R3 should be expanded to provide guidance on how to demonstrate a unit is capable of operating at/below ECWT. Cold Weather Event with a number of units on economic reserve, who dictates the “start-up failure within a specified time”? And where would that be documented?

Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	
Document Name	NAGF EOP-012-2 Comment Form Draft 3.docx
Comment	
Likes 0	
Dislikes 0	
Response	