Consideration of Comments

Project Name:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination - Phase 2 | Draft 2 - EOP-011-4 and TOP-002-5
Comment Period Start Date:	8/24/2023
Comment Period End Date:	9/12/2023
Associated Ballot(s):	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 EOP-011-4 | Non-binding Poll AB 2 NB 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 EOP-011-4 AB 2 ST 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 Implementation Plan AB 2 OT 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 TOP-002-5 | Non-binding Poll AB 2 NB 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 TOP-002-5 AB 2 ST

There were 62 sets of responses, including comments from approximately 152 different people from approximately 106 companies representing 10 of the Industry Segments as shown in the table on the following pages.

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

If you feel that your comment has been overlooked, let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, contact Vice President of Engineering and Standards, Soo Jin Kim (via email) or at (404) 446-9742.

In response to industry comments, the Standard Drafting Team (SDT) has made a few clarifying non-substantive changes to EOP-011 and TOP-002. The SDT provides the following summary of the changes, which are discussed in more detail in the Technical Rationale and in the response to comments below.

For EOP-011-4 the changes include:

- "as defined by the Applicable Entity" clarified in Parts 1.2.5.5, 2.2.8 and 8.1.5 – Based on multiple comments received, the team added this phrase to clarify who is responsible for determining critical natural gas infrastructure loads as an electric entity, not a gas entity.
- Clarifying automatic load shed as undervoltage and underfrequency load shed – Based on multiple comments received, the team has clarified that automatic load shed in this context is undervoltage Load shed and underfrequency Load shed and does not include other things such as Remedial Action Schemes or Special Protection Schemes.
- Additional language in effective date regarding being compliant with R8 within 30 calendar months – Based on comments received the detail of 30 months was moved from the requirement language and added to the effective date section of the standard. This will also allow entities to be able to refer to one document, the standard, as it becomes effective and not also have to have the Implementation Plan up for reference also.

TOP-002 changes include:

- Removal of Interchange Scheduling from Part 8.2 – Based on comments received, the team removed this requirement in R8 Part 8.3 because this function is typically done in real time on an hourly basis. The need for the Balancing Authority to proactively look ahead and forecast their ability to import power from neighboring Control Areas is captured under Parts 8.3.1 and 8.3.3.

Questions

EOP-011-4 (Questions 1-3)

1. Do you agree with the new R7 for identification and notification?

2. Is the 30-month time frame in R8 adequate time for the physical changes that may be required to comply with these requirements?

3. The SDT has elected to add clarifying language in the applicable requirements in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities and their relative impact on the BES. Do you agree with this approach?

TOP-002-5 (Question 4)

4. The SDT modified the proposed Requirement R8 to remove the link between the required Operating Process and the Operating Plan required under Requirement R4. Do you agree with this modification?

General (Questions 5-7)

5. The SDT proposes that the modifications in EOP-011-4 and TOP-002-5 meet the key recommendations in The Report 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.

6. Do you agree with the implementation plan proposed by the SDT? 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.

7. Provide any additional comments for the SDT to consider, including the provided technical rationale document, if desired.

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
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
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
					Scott Brame	North Carolina Electric Membership Corporation	1,3,4,5	SERC
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	SERC
					Nikki Carson-Marquis	Minnkota Power Cooperative, Inc.	1	MRO
					Nikki Carson-Marquis	Minnkota Power Cooperative, Inc.	1	MRO
					Jordan Mcclellan	Southern Illinois Power Cooperative	1	SERC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC

					Vicki O'Leary	Eversource Energy	3	NPCC
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 -	1	MRO

						MidAmerican Energy Co.		
					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
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
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Alain Mukama	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC

John Pearson	ISO New England, Inc.	2	NPCC
Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC
Randy MacDonald	New Brunswick Power Corporation	2	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
David Burke	Orange and Rockland	3	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
David Kwan	Ontario Power Generation	4	NPCC

					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
Dominion - Dominion	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable

Resources, Inc.					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Stephen Whaite	Stephen Whaite			ReliabilityFirst Ballot Body Member and Proxies	Lindsey Mannion	ReliabilityFirst	10	RF
					Stephen Whaite	ReliabilityFirst	10	RF
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC

					Kevin Smith	Balancing Authority of Northern California	1	WECC

EOP-011-4 (Questions 1-3)

1. Do you agree with the new R7 for identification and notification?

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
MRO NSRF disagrees with R7. As it is currently written, the elements outlined in R7 should be incorporated as a subcomponent of R1. For a Transmission Operator to successfully develop, maintain, and implement an Operating Plan, as mandated by R1, the Transmission Operator must also and initially (and as necessary or required moving forward) notify relevant entities, which is the action specified in R7.	
Likes 3	OGE Energy - Oklahoma Gas and Electric Co., 3, Hargrove Donald; OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri; JEA, 1, McClung Joseph
Dislikes 0	
Response	
Thank you for your comment. The identification and notification provisions in R7 have been structured as a separate requirement to allow for a specific triggering event for entities subject to R8 and for clarity in the Implementation Plan.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Without fully knowing what expectations will result from our TOP (PJM), FirstEnergy cannot support this new requirement.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren is unsure how we are supposed to know what registered Distribution Providers are in our Transmission Operator Area. We suggest some sort of automatic notification when a new Distribution Provider becomes registered within our Transmission Operator Area, or an easily accessible list of Distribution Providers.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Functional mapping in CORES requires new entities to identify certain upstream relationships. The process is explained in the ERO Registration Procedure. For more information, please contact NERC Registration.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
1. NCPA supports others opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State somewhat agrees with R7 but would like clarity on the following: }If an entity has unplanned or unusual circumstances that may not fall under “operating emergency” situations where they ask for manual load shed to occur when it normally wouldn’t will they still be required to notify the Distribution Providers/Transmission Owners under R7?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. If a Transmission Operator relies on a DP, UFLS-Only DP, or TO to assist with the mitigation of operating Emergencies in its Transmission Operator Area, then identification and notification of those entities would be required under R7.	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	
NCPA supports comments others' opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	No
Document Name	
Comment	
The notification should be required to be given initially and upon changes, and reviewed at least annually.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The annual identification and notification in R7 will capture any changes.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
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	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the new R7 language for identification and notification.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
The current wording reads like it is missing what the entities are being notified of as the purpose reads to be part of the entity classification not that they are being notified that they are required to assist with mitigation.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Requirement R8 refers back to R7 and provides a specific tie back to the purpose of the notification.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM and TNMP supports the new identification and notification language in R7.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the new R7 for identification and notification.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes

Document Name	
Comment	
EEI supports the new R7 language for identification and notification.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
ISO-NE agrees with the SRC that the term "automatic Load shedding" be replaced with "undervoltage Load shedding or underfrequency Load shedding" throughout EOP-011-4. Thus eliminating normal SPS/RAS operations from the EOP-011 requirements	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees and has made these changes for the final ballot.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

The drafting team should consider whether the addition of sub-requirements could enhance clarity and provide more flexibility for this TOP task. For example, following the initial performance of R7 the TOP might annually review the list of entities previously identified and only notify any newly identified entities that their assistance is needed. For entities that have previously been notified, the need for their continued assistance could be communicated annually and the status of their implementation readiness requested. A provision could also be added to allow the TOP to extend the 30-month initial implementation for an entity subject to R8 when justifiable conditions warrant.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed and has chosen to keep the current structure of R7 as the team believes annual notification is needed.	
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 with the new R7 for identification and notification.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	

Comment	
The ISO/RTO Council (IRC) Standards Review Committee (SRC) (consisting, for purposes of these comments, of CAISO, ERCOT, IESO, ISO-NE, PJM, MISO, and SPP) agrees with the new requirement R7, but recommends that the term “automatic Load shedding” be replaced with “undervoltage Load shedding or underfrequency Load shedding” throughout EOP-011-4. The term “automatic Load shedding” encompasses more than just UVLS or UFLS Load shedding. Specifically, it may be interpreted to include other frameworks that may involve automatic load Shedding, such as Remedial Action Schemes (which are addressed by PRC-012-2), that are not necessarily used to assist with the mitigation of operating Emergencies and are therefore outside the scope of EOP-011-4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees and has made these changes for the final ballot.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
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	

Diana Torres - Imperial Irrigation District - 1,3,5,6	
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	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Hillary Creurer - Allete - Minnesota Power, Inc. - 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; Terry Gifford, 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	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
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	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Matt Lewis - Lower Colorado River Authority - 1	
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	

Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
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	
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	
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	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
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	
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	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
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	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
Does not apply to Reclamation.	
Likes 0	
Dislikes 0	
Response	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	
Document Name	

Comment	
We support the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE appreciates and supports the standard drafting team's (SDT) efforts in address the Joint Inquiry report for Winter Storm Uri. Texas RE recommends there be a requirement for the DP, DPUF, and TO to acknowledge receipt of the notification that they are required to assist with mitigation of operating Emergencies. Additionally, Texas RE is concerned with the 30-month implementation of a Load shed plan in Requirement R8. Texas RE requests the SDT's justification for a 30-month implementation of developing a load shed plan. Furthermore, Requirement R7 does not provide specific detail what is required assist with the mitigation of operating Emergencies so it is unclear why a 30-month implementation is necessary.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

The SDT discussed and has declined to add a requirement for DPs, UFLS-Only DPs, and TOs to acknowledge receipt of a notification under R7 appears to be administrative in nature and does not enhance reliability. (See Paragraph 81 criteria from Project 2013-02)

The 30-month implementation timeframe was selected to allow adequate time for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. Additional language was added to the Implementation Plan for the final ballot to clarify that this timeframe is not intended to extend the timeframe for an entity's existing responsibilities under EOP-011-2 or EOP-011-3; rather, the additional timeframe is intended to provide additional time to come into compliance with new and revised requirements specific to EOP-011-4.

Regarding R7, Requirement R8 refers back to R7 and provides a specific tie back to the purpose of the notification.

2. Is the 30-month time frame in R8 adequate time for the physical changes that may be required to comply with these requirements?

Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	No
Document Name	
Comment	
Thirty months is too long to make the plan. Possibly there could be a separate timetable applied. 6-12 months to establish and communicate the emergency plan to the TOP and the efforts needed to be able to implement it. This allows the TOP time comment and coordinate for any concerns ahead of time. Something like an additional 18 months if new equipment, etc. is needed to be able to implement/support the plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed and has chosen to keep current timeline and structure of the Implementation Plan as the team believes the 30-month implementation timeframe is necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This change was made to provide adequate time for budgeting, acquiring, and installing new physical equipment.	
Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	
NCPA supports comments others' opposing comments that have been submitted.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
1. NCPA supports others opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	

Answer	No
Document Name	
Comment	
For EOP-011, Seminole proposes a 36-month implementation time frame. The coordination and agreements between multiple DPs and multiple DPs in multiple TOs' areas could possibly take a significant amount of time. For TOP-002, Seminole proposes an 18 month implementation time frame to remain consistent with other revisions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The team believes that the 30-month implementation time frame for EOP-011-4 (Part 1.2.5, 2.2.8 and 2.2.9) is sufficient for budgeting, acquiring, and installing new physical equipment. The team is proposing an 18-month implementation time frame for TOP-002-5.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren would like more clarification around the phrase "physical changes." Due to the long lead times in today's environment, it is hard to make a 30-month commitment if there are changes that require a longer time to implement.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The phrase "physical changes" refers to changes that may be required to UFLS circuits in response to 1.2.5.2, 1.2.5.5, 8.1.2, and 8.1.5.	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Without fully knowing what expectations will result from our TOP (PJM), FirstEnergy cannot support this time frame	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes 30 months is too short of a timeframe to address physical infrastructure changes. Without knowing the scope of how many “critical natural gas infrastructure loads” there are throughout the entire Pacific Northwest and how many UFLS relays would need to be relocated, designed and installed, BPA cannot commit to a 30 month implementation. BPA reiterates its comments from the previous comment period and recommends a longer, phased in approach, similar to PRC-005 (PSMP) or PRC-002 (Equipment Monitoring). This would include a timeframe to identify loads and an additional timeframe to design, schedule, and install any required elements.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The team believes that the 30-month implementation time frame for EOP-011-4 (Part 1.2.5, 2.2.8 and 2.2.9) is sufficient for budgeting, acquiring, and installing new physical equipment.	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
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.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The team believes that the 30-month implementation time frame for EOP-011-4 (Part 1.2.5, 2.2.8 and 2.2.9) is sufficient for budgeting, acquiring, and installing new physical equipment.	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
As detailed in its response to question 6, below, the SRC believes that entities that already assist with Load shed should only need a 30-month timeframe for part 8.1.5 and should have a shorter timeframe for the remaining parts of R8. Additionally, the SRC believes that the implementation plan adequately addresses the implementation timeframe for R8 for both new and existing entities, and that including the 30-month timeframe in R8 is therefore redundant. Consequently, the SRC recommends that references to the 30-month timeframe be removed from R8 in the interests of clarity and efficiency.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Additional language was added to the Implementation Plan for the final ballot to clarify that the 30-month timeframe is not intended to extend the timeframe for an entity's existing responsibilities under EOP-011-2 or EOP-011-3; rather, the additional timeframe is intended to provide additional time to come into compliance with new and revised requirements specific to EOP-011-4.

The 30-month timeframe has been removed from R8 for clarity. This has been replaced with language in the Implementation Plan and Effective Date section of EOP-011-4.

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 believes that 30 months is adequate for those DPs, UFLS-Only DPs, and TOs that are identified in R7.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
The proposed R7 would require TOPs to "annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding or automatic Load shedding". The Distribution Providers, UFLS-Only Distribution Providers and	

Transmission Owners that are the recipients of such TOP notifications would then have 30-months to "develop, maintain, and implement a Load shedding plan" that must have the capability of being "operator-controlled" (as reflected in R8, Part 8.1). We interpret the term "operator-controlled" to mean controllable by a NERC defined System Operator (in this case, the TOP). If the TOP has an annual obligation to "identify and notify", but the recipient(s) of such notifications have 30-months to develop and implement an associated Load shedding plan (the "maintain" part would not kick in until after the initial Load-shedding plan is developed and implemented), a TOP could conceivably issue three annual notifications under R7 before a recipient completes its initial performance of R8. The drafting team should consider whether the 30-month interval for an initial performance of R8 is sufficiently covered within the implementation plan and can be removed from the requirement language.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Additional language was added to the Implementation Plan for the final ballot to clarify that this timeframe is not intended to extend the timeframe for an entity's existing responsibilities under EOP-011-2 or EOP-011-3; rather, the additional timeframe is intended to provide additional time to come into compliance with new and revised requirements specific to EOP-011-4. The 30-month timeframe has been removed from R8 for clarity. This has been replaced with language in the Implementation Plan and Effective Date section of EOP-011-4.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
ISO-NE supports the 30-month time frame for physical changes.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed 30-month time frame for DPs, UFLS-Only DPs, and TOs to make changes in conformance with Requirement R7 notifications.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS supports the 30-month time frame in R8 for physical changes that may be required to comply.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM and TNMP supports the proposed 30-month time frame for DPs, UFLS-Only DPs, and TOs to make changes in conformance with Requirement R7 notifications.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
It is not clear what the intent of requirement 2.2.8 is and whether this requires exclusion of natural gas infrastructure loads only during extreme cold weather periods? If this is a requirement, a 30 month implementation of such a system requirement may be more technically challenging and take a longer period of time to implement.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. In the second ballot, the SDT discussed whether the exclusion of critical natural gas infrastructure loads as Interruptible Load, curtailable Load, and demand response should be limited to certain situations or be a complete prohibition. The SDT has limited the exclusion of these loads from Interruptible Load, curtailable Load, and demand response only to periods of extreme cold weather as identified in the SAR. Entities should note that the proposed Standard represents a minimum requirement which can be exceeded by individual entities if deemed appropriate.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
While a 30 month time frame seems reasonable, AEP requests that it be revised to instead state 30 *calendar* months.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The 30-month timeframe has been removed from R8 for clarity. This has been replaced with language in the Implementation Plan and Effective Date section of EOP-011-4. This now refers to "calendar" months.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the proposed 30-month time frame for DPs, UFLS-Only DPs, and TOs to make changes in conformance with Requirement R7 notifications.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
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	
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	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - 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	
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	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
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	
Matt Lewis - Lower Colorado River Authority - 1	
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	
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; Terry Gifford, 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	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

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

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	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
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	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 2	OGE Energy - Oklahoma Gas and Electric Co., 3, Hargrove Donald; OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
Dislikes 0	

Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
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	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE agrees that 30 months is adequate for physical changes that may be required to comply with Requirement R7. Texas RE is concerned, however, with the 30-month time frame for non-physical changes. The concern is that the TOP would not be able to mitigate an Operating Emergency seen in the next year if it has to wait 30 months for the DP, DP UFLS, or TO's Load shed plan if there are no physical changes needed and there is simply an update to the plan itself. Texas RE recommends that if there are no physical changes needed, the timeline should be shorter.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The 30-month implementation timeframe was selected and allows adequate time for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. The team supports entities becoming compliant prior to the proposed date. The proposal above would make implementation significantly more confusing.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	

Comment	
The NAGF does not take a position on this issue.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	
Document Name	
Comment	
We support the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

3. The SDT has elected to add clarifying language in the applicable requirements in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities and their relative impact on the BES. Do you agree with this approach?

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

MRO NSRF appreciates the SDT's effort to strike a balanced approach concerning the term "critical natural gas infrastructure load." However, MRO NSRF maintains that if the standard incorporates this term, it must be well-defined to facilitate the effective identification and prioritization by Transmission Operators. Although the specific operational equipment qualifying as "critical natural gas infrastructure load" may vary across or even within regions, the fundamental characteristics of what constitutes a “critical natural gas infrastructure load” and the reliability risks that they may pose to the Bulk Electric System (BES) remain constant.

Additionally, MRO NSRF is concerned about the practicality of implementing a requirement that explicitly relies on the coordination with natural gas facility owners and operators for successful implementation. The Technical Rational notes that achieving this coordination relies on the voluntary cooperation of these natural gas entities. At the same time, it acknowledges that the SDT (nor NERC) has the authority to enforce such cooperation. MRO NSRF finds it problematic to mandate, through an enforceable reliability standard, an action that entities cannot guarantee the completion of due to factors beyond their control.

Likes 3	OGE Energy - Oklahoma Gas and Electric Co., 3, Hargrove Donald; OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri; JEA, 1, McClung Joseph
Dislikes 0	
Response	

Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality. The SDT maintains the position that it is most appropriate to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
Although there may be varying definitions that exist across the NERC footprint for “critical natural gas infrastructure load,” NERC should nonetheless pursue a standardized definition to provide a minimum threshold as to what “critical natural gas infrastructure load” is. (Note: This would also allow for more restrictive regional or local definitions where desired.)	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality. The SDT maintains the position that it is most appropriate to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation.	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	

By specifically identifying natural gas infrastructure loads, other critical industries are excluded. Reclamation recommends removing requirement R8.1.5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT can only address critical natural gas infrastructure loads per the SAR. Requirements 8.1.5 is specific to critical natural gas infrastructure in response to specific recommendations from the joint inquiry report. Requirements 1.2.5.2 and 8.1.2 more broadly address “critical loads which are essential to the reliability of the BES.”	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes the obligation of Responsible Entities to comply with EOP-011’s requirements should not depend on the extent to which natural gas providers are willing to voluntarily work with Responsible Entities to identify critical natural gas infrastructure loads. The SDT noted it does not have the scope to develop methods to compel natural gas facility owners and operators to cooperate and provide specific information; the same is true of the Responsible Entities. With Transmission Entities having no legal or regulatory means to “require” natural gas facility owners to self- identify critical natural loads, BPA believes this sets industry up for failure when attempting to meet these revised requirements. This might need to go to a FERC level to require natural gas facility owners to self-identify critical natural loads to Transmission Entities. BPA cannot assure its compliance if it’s based upon voluntary actions that natural gas companies might not be willing to complete. BPA understands that the information needed would be highly confidential, and represents a very high national security risk. Critical natural gas facility information will likely be closely guarded and not readily shared.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality. The SDT maintains the position that it is most appropriate to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP is unsure exactly what "clarifying language" is that Question 3 is referencing. If it is in regards to the addition of "critical loads which are essential to the reliability of the BES", AEP disagrees with their proposed inclusion. Please see our response to Question 7 where our concerns are expressed in more detail.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response to Question 7.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy believes this still does not address our concern toward clarity of what will be deemed critical and who will determine that designation.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality. The SDT maintains the position that it is most appropriate to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation.	
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; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power appreciates the efforts of the SDT to balance the approach to identifying critical natural gas infrastructure and not limiting entities in their identification methods. However, if the Standard incorporates this term, it must be well-defined to facilitate the effective identification and prioritization by Transmission Operators. Tacoma Power concurs that specific operational equipment qualifying as "critical natural gas infrastructure load" may vary across or even within regions. This variation is why it's important that the fundamental characteristics of what constitutes a "critical natural gas infrastructure load" and the reliability risks that they may pose to the Bulk Electric System (BES) remain constant. Tacoma Power is concerned without these characteristics defined, each entity or auditor will have a different definition of what is considered "critical."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality. The SDT maintains the position that it is most appropriate to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation.	

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren understands the flexibility to identify critical natural gas loads, but would like guidelines as to what is considered critical. Ameren would also like a definition of extreme cold weather in the standard or in the glossary of terms.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality. The SDT maintains the position that it is most appropriate to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. The SDT discussed and decided against creating a definition for extreme cold weather allowing flexibility for entities to create their own definition based on their unique facts and circumstances.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
1. NCPA supports others opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State supports the MRO NSRF comments for this question: "MRO NSRF appreciates the SDT's effort to strike a balanced approach concerning the term "critical natural gas infrastructure load." However, MRO NSRF maintains that if the standard incorporates this term, it must be well-defined to facilitate the effective identification and prioritization by Transmission Operators. Although the specific operational equipment qualifying as "critical natural gas infrastructure load" may vary across or even within regions, the fundamental characteristics of what constitutes a "critical natural gas infrastructure load" and the reliability risks that they may pose to the Bulk Electric System (BES) remain constant." "Additionally, MRO NSRF is concerned about the practicality of implementing a requirement that explicitly relies on the coordination with natural gas facility owners and operators for successful implementation. The Technical Rational notes that achieving this coordination relies on the voluntary cooperation of these natural gas entities. At the same time, it acknowledges that the SDT (nor NERC) has the authority to enforce such cooperation. MRO NSRF finds it problematic to mandate, through an enforceable reliability standard, an action that entities cannot guarantee the completion of due to factors beyond their control."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality. The SDT maintains the position that it is most appropriate to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation.	

Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	
NCPA supports comments others' opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	

Comment	
Dominion Energy supports the EEI comments and is of the opinion that the SDT should add additional clarifying language to ensure that the Applicable Entity makes the final determination of these loads prior to a final ballot.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
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	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the SDT's approach and agrees that the added language is superior to defining "critical natural gas infrastructure load". WEC Energy Group also agrees that the SDT should not try to define this term since the equipment subject to being considered critical could change over time. In addition, allowing the BA, TOP and DP to work with the customer is more likely to provide better end results than a definition created by this SDT.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
Answer	Yes
Document Name	
Comment	
This was clarified for 1.2.5.5., but was not clarified in 1.2.5.2. It is recommended similar clarification also be applied to 1.2.5.2 regarding the critical natural gas infrastructure.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Critical natural gas infrastructure is one type of designated critical load that may be addressed in Requirement 1.2.5.2.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
No omments	
Likes 0	
Dislikes 0	
Response	

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM and TNMP agrees the including language in the standard to support the term "critical natural gas infrastructure load" vice creating a new definition; however, we support EEI's comment regarding the addition of "as defined by the responsible entity" to the standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the clarifying language.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	

Answer	Yes
Document Name	
Comment	
The NAGF agrees that the SDT should not try to define this term since the equipment subject to being considered critical could change over time. In addition, allowing the BA, TOP and DP to work with the customer is more likely to provide better end results than a definition created by this SDT.	
Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
Dislikes 0	
Response	
Thank you for your comment.	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
We agree as long as this approach is remembered down the road.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	

Comment	
EEI supports the SDT's approach and agrees that the added language is superior to defining "critical natural gas infrastructure load", however, to ensure further clarity and to align with the technical rational, we ask the SDT to consider the following edits to those instances where this phrase is used (see our proposed edits in bold face below). critical natural gas infrastructure loads which are essential to the reliability of the BES **as defined by the responsible TO/DP**	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
The drafting team should consider whether all the entities subject to the proposed R8 will have the information needed to identify and prioritize "designated critical natural gas infrastructure loads which are essential to the reliability of the BES" (R8, Part 8.1.5). The proposed standard essentially assigns this task to five different entities (TOP in R1, Part 1.2.5.5; BA in R2, Part 2.2.8; and DP/UFLS-Only DP/TO in R8, Part 8.1.5) with no indication of coordination or shared understanding.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality.	
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 that the added language is superior to defining "critical natural gas infrastructure load".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
SMUD and BANC support the comments submitted by the EEI.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
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	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

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	
Matt Lewis - Lower Colorado River Authority - 1	
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	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
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	
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	
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	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
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	
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	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
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	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	
Document Name	
Comment	
We support the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

TOP-002-5 (Question 4)

4. The SDT modified the proposed Requirement R8 to remove the link between the required Operating Process and the Operating Plan required under Requirement R4. Do you agree with this modification?

Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	
NCPA supports comments others' opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No
Document Name	
Comment	
8.2 is awkward, and it is not clear if the load shedding plan should be submitted to the TOP for review and approval; or, if there must be provisions in the plan to submit the plan to the TOP for review. This will be a problem during enforcement, where an entity may submit their plan for approval by the TOP, for review, but fails to have a process for submitting the plan, in the plan. Implementation of the plan would reasonably be expected when there is a system emergency that requires load shedding; however, R8 could be read as 30 days to implement when notified by the TOP. This may sound like a petty issue; however, these issues always crop up and the wording should be improved. Regarding M8, and evidence suggested for developing, maintaining and implementing a Load Plan: There is nothing required to show the plan was approved by the TOP; or, if the TOP did not approve, the process requiring the resolution of the issues and subsequent resubmission and approval.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The SDT discussed your concern and believes that some clarification is in order. There is no intent to require the BA to submit the Operating Process for Extreme Cold Weather to the TOPs for review or approval. As such, there are no enforcement issues to resolve. Load shedding and system emergencies are subject to the Emergency Operating Plans under EOP-011. The Operating Process under TOP-002 is supplemental to the Operating Plan. Again, there is no requirement nor intent for the TOP to approve or implement a load plan under R8 of TOP-002.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No

Document Name	
Comment	
1. NCPA supports others opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
TOP-002 provides requirements for the Operational Planning Analysis, which is performed on a daily basis. The detailed requirements for the Extreme Cold Weather plan enumerated in R8 will be performed only when specific criteria are met. BPA believes the details of the cold weather plan belongs in another standard, probably EOP-011.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed your concern and clarifies the Operating Process under TOP-002 is supplemental to the Operating Plan, and the BAs Operational Planning Analysis. Its intent is to analyze conditions during upcoming extreme cold weather periods with the intent to mitigate the declaration of an emergency and implementation of emergency operating plans under EOP-011.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	

Comment	
Part 8.3: MISO remains concerned that the term "forecast" is typically used to denote weather forecasts only and would not typically encompass the items under Part 8.3 which is more akin to an Operating Plan described under requirement R4. We agree the Operating Plan should be adequate to meet the timeframe for the identified extreme cold weather period; however, requiring a **five-day forecast** for every "identified extreme cold weather period" may not be necessary. To provide flexibility, MISO suggests the language provided below: **8.3** A methodology to determine an adequate Operating Plan during the identified (or forecasted) extreme cold weather periods… As detailed in prior SRC comments submitted regarding draft 1 of TOP-002-5, MISO continues to be concerned that the approach taken in TOP-002-5 is not the most cost-effective approach due to the lack of corresponding requirements on the GO/GOP to provide the BA with information needed by the BA to fulfill its obligations. Historically, when this has happened, the BA has incurred additional costs and delays in obtaining the information needed as the BA must develop and employ alternative processes (e.g., modifications to FERC tariffs, revisions to membership agreements, engagement in regional rulemaking processes, modifications to its TOP-003 specifications, etc.). Ultimately, the GO/GOP must provide the data; however, it is much more labor intensive than if the obligation to provide data is in the Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed and decided to retain the five-day forecast requirement (see Technical Rationale for TOP-002). Additionally, the SDT discussed the issue of data specification, and in consultation with NERC, determined that all information required by the BA to perform its analysis is available under TOP-003. The current requirements in TOP-003 express the minimum required, however, the language "but not limited to" provides the avenue for the BA to obtain additional data points required to perform real-time assessments and real-time monitoring and other analysis required under TOP-002.	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
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 with the modifications to R8 that distinguish the BA's extreme cold weather Operating Process from the BA's Operating Plan.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
We believe R8, Part 8.1 should be modified to read “A methodology for identifying an extreme cold weather period within **their** Balancing Authority Area;”.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. The SDT has made modifications to R8 to more expressly detail the intent.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
No Additional Comments	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees with the modification to Requirement R8 that distinguish the BA's extreme cold weather Operating Process from the BA's Operating Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF believes that the BA can decide how it can best implement this requirement, whether by using it as part of their Operating Plan or having a separate process to address cold weather efforts.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
David Jendras Sr - Ameren - Ameren Services - 3	

Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the modification to R8.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	

PNM and TNMP both agree with the modification to Requirement R8 that distinguish the BA’s extreme cold weather Operating Process from the BA’s Operating Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas and Electric Company supports the removal of the link between R4 and R8 with the understanding that R4 and R8 will be the responsibility of the Balancing Authority.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Language has made this clear.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group agrees with the modification to Requirement R8 that distinguish the BA's extreme cold weather Operating Process from the BA's Operating Plan. WEC Energy Group also believes that the BA can decide how it can best implement this requirement, whether by using it as part of their Operating Plan or having a separate process to address cold weather efforts.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lenise Kimes - City and County of San Francisco - 1 - WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 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	
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	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - 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	
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	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
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	
Matt Lewis - Lower Colorado River Authority - 1	
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	

Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
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; Terry Gifford, 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	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 1, 6, 5; Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, 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	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
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	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
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	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 2	OGE Energy - Oklahoma Gas and Electric Co., 3, Hargrove Donald; OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
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	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	
Document Name	
Comment	
We support the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	

Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
Does not apply to Reclamation	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

General (Questions 5-7)

5. The SDT proposes that the modifications in EOP-011-4 and TOP-002-5 meet the key recommendations in The Report 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.

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
As detailed in prior SRC comments regarding draft 1 of TOP-002-5, MISO continues to be concerned that the approach taken in TOP-002-5 is not the most cost-effective approach due to the lack of corresponding requirements on the GO/GOP to provide the BA with information needed by the BA to fulfill its obligations. Historically, when this has happened, the BA has incurred additional costs to obtain the information needed. This increases the overall cost of compliance as the BA must develop and employ alternative processes to obtain the data needed (e.g., modifications to FERC tariffs, revisions to membership agreements, engagement in regional rulemaking processes, etc.). Ultimately, the GO/GOP ends up incurring the cost to provide the data to the BA; however, costs to the BA accrue because of delays and the need for quality assurance associated with lower quality data than if the obligation to provide data had been enshrined in a Reliability Standard or other regulatory rule.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed additional reporting requirements for the GO/GOP and the team determined that the data specifications under TOP-003 provide the best avenue for BAs to request and receive any data necessary.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No

Document Name	
Comment	
Related to our Q1 response, without a scope of expectations, we cannot determine the cost effectiveness of these recommendations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
1. NCPA supports others opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No
Document Name	
Comment	
The authority for the TOP and BA to direct, or give Operating Instructions, is already well established in TOP-001 R1 through R5, and it seems this standard is fundamentally not needed. It further exposes TOs and DPs to unnecessary administrative and compliance burden to have	

load shedding plans that must be created and maintained. During audits, non-compliance penalties are assessed for small omissions, and potential violations based on the auditors' subjective authority to determine the quality of the documentation. When entities must comply to directives and Operating Instructions, maintaining written plans that, may or not be suitable for the situation, adds a significant level of cost without benefit. This is especially true of smaller entities who have limited load or resources.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT developed these new requirements to ensure BAs consider past extreme cold weather.	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, The SDT has not provided any cost estimate to support their proposal and has not provided a cost/benefit justification. It appears this entire proposal/endeavor will not improve reliability and simply just keeps more people busy doing more paperwork. Consequently, we feel it is not cost effective, not productive, and not prudent use of customer dollars.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SAR scope requires modifications for reliability purposes. The SDT is not aware of any more cost-effective solutions to address the recommendations within the scope of the SAR.	
Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	

Comment	
NCPA supports comments others' opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
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 agrees.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
It is not clear what the intent of requirement 2.2.8 is and whether this requires exclusion of natural gas infrastructure loads only during extreme cold weather periods? If this is a requirement, the implementation may not be cost-effective as intended.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. In the second ballot, the SDT discussed whether the exclusion of critical natural gas infrastructure loads as Interruptible Load, curtailable Load, and demand response should be limited to certain situations or be a complete prohibition. The SDT has	

limited the exclusion of these loads from Interruptible Load, curtailable Load, and demand response only to periods of extreme cold weather as identified in the SAR. Entities should note that the proposed Standard represents a minimum requirement which can be exceeded by individual entities if deemed appropriate.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM and TNMP agree that the key recommendations and be implemented in a cost-effective manner.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Micah Runner - Black Hills Corporation - 1	

Answer	Yes
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	

Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
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 does not think this answer will be known until everything is fully implemented.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	Yes
Document Name	
Comment	
What is the definition of “cost-effective”? Who is responsible for determining if it is cost-effective? Is it a coordinated effort between the DP, TO and TOP?	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The intent of this question was for individual entities to provide comments on cost effectiveness based on their unique situation and the requirements they are required to comply with. The SDT is not aware of any more cost-effective solutions to address the recommendations within the scope of the SAR.

Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 3, Hargrove Donald
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
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	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
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	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 1, 6, 5; Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, 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	
Hillary Creurer - Allete - Minnesota Power, Inc. - 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; Terry Gifford, 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	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Matt Lewis - Lower Colorado River Authority - 1	
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	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 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	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 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	

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

Likes 0	
Dislikes 0	
Response	
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	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy’s focus is to assure the effective and efficient reduction of risks to the reliability and security of the grid and will not provide comments on the cost effectiveness of the proposed changes.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
Does not apply to Reclamation	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CEHE abstains.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	
Document Name	
Comment	
We support the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
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	
Thank you for your comment.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	
Document Name	

Comment	
It seems that no matter how this Standard is written there will be some associated costs with implementation. ISO-NE does not have a recommendation for how to avoid those cost issues.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

6. Do you agree with the implementation plan proposed by the SDT? 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.

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

While requirement R8 is a newly written requirement that is specific to Distribution Providers, UFLS-only Distribution Providers, and Transmission Owners, some DPs, UFLS-only DPs, and TOs already assist with Load shedding. The SRC believes that the implementation plan should be revised to require that these entities that already assist with Load shedding be in compliance with all parts of requirement R8 except part 8.1.5 by the effective date of EOP-011-4. All entities required to comply with R8 should receive the full 30 months to comply with part 8.1.5, which contains the newly added provisions for the identification and prioritization of designated critical natural gas infrastructure loads that are essential to the reliability of the BES.

Additionally, ERCOT makes the following comment individually; the SRC does not join this paragraph: ERCOT recommends a 24-month implementation timeframe for both standards to account for the coordination, budget revisions, staffing changes, and systems upgrades necessary to accomplish the new tasks. New forecasts and tools often require multiple projects to acquire the necessary input data and to process and display that data to users. This often requires extensive testing as well.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT discussed your suggested changes to the Implementation Plan and determined it is not necessary to make these changes, since the DPs, UFLS-only DPs, and TOs should have sufficient time to make any necessary adjustments to their Load-shed program with the timeframes already specified in the Implementation Plan.

Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	No
Document Name	
Comment	
See #2 above. Agree with other implementation time frames.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed your suggested changes to the Implementation Plan and determined it is not necessary to make these changes, since the DPs, UFLS-only DPs, and TOs should have sufficient time to make any necessary adjustments to their Load-shed program with the timeframes already specified in the Implementation Plan.	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
The SDT has not provided any cost estimate to support their proposal and has not proved a cost/benefit justification. It appears this entire proposal/endeavor will not improve reliability and simply just keep more people busy doing more paperwork. Consequently, we feel it is not cost effective, not productive, and not prudent us of customer dollars.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT focused on achieving the reliability benefits outlined in the SAR.	

Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	
The SDT has not provided any cost estimate to support their proposal and has not proved a cost/benefit justification. It appears this entire proposal/endeavor will not improve reliability and simply just keep more people busy doing more paperwork. Consequently, we feel it is not cost effective, not productive, and not prudent us of customer dollars.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT focused on achieving the reliability benefits outlined in the SAR.	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT addressed all comments received.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No

Document Name	
Comment	
No, we believe the rules of procedure may need to be changed around the TO and DP functions before the full implementation can be made.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Changes to the Rules of Procedure are beyond the scope of this SDT. The SDT believes entities are able to implement the requirements of the standard under the existing ROP.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC has signed on to ACES comments: We have concerns with the phased implementation plan timelines for Requirements R1 Part 1.2.5 and Requirement R2 Part 2.2.8 and Part 2.2.9 being identical. The proposed text of Part 2.2.9 specifically states “in accordance with Requirement R1 Part 1.2.5”; therefore, as Part 2.2.9 is dependent upon R1 Part 1.2.5, we recommend modifying the implementation plan to account for this dependency.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The 30 months implementation date is appropriate for both the BA and TOP to develop its own load shedding plans. The BAs load shedding plans are not at the same granularity as the TOPs, and are generally not facility specific. The BAs load shedding	

plan is for its entire Balancing Authority Area (BAA), and consistent with the current construct, requires the TOPs within the BAA to shed the TOP's share of aggregated load within its own TOP area and according to the TOPs plan. Therefore, the BAs ability to develop a lead shedding plan for its Balancing Authority Area is not dependent on the TOP to first develop its load shedding plan for the specific facilities within its TOP area. Rather, the BA and TOPs can create their own specific load shedding plans within the 30 months implementation timeframe; and upon implementation, the BA can require the TOP to shed its aggregated load share pursuant to the new requirements.	
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 have concerns with the phased implementation plan timelines for Requirements R1 Part 1.2.5 and Requirement R2 Part 2.2.8 and Part 2.2.9 being identical. The proposed text of Part 2.2.9 specifically states "in accordance with Requirement R1 Part 1.2.5"; therefore, as Part 2.2.9 is dependent upon R1 Part 1.2.5, we recommend modifying the implementation plan to account for this dependency.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The 30 months implementation date is appropriate for both the BA and TOP to develop its own load shedding plans. The BAs load shedding plans are not at the same granularity as the TOPs, and are generally not facility specific. The BAs load shedding plan is for its entire Balancing Authority Area (BAA), and consistent with the current construct, requires the TOPs within the BAA to shed the TOP's share of aggregated load within its own TOP area and according to the TOPs plan. Therefore, the BAs ability to develop a lead shedding plan for its Balancing Authority Area is not dependent on the TOP to first develop its load shedding plan for the specific facilities within its TOP area. Rather, the BA and TOPs can create their own specific load shedding plans within the 30 months implementation timeframe; and upon implementation, the BA can require the TOP to shed its aggregated load share pursuant to the new requirements.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No

Document Name	
Comment	
The SDT has not provided any cost estimate to support their proposal and has not proved a cost/benefit justification. It appears this entire proposal/endeavor will not improve reliability and simply just keep more people busy doing more paperwork. Consequently, we feel it is not cost effective, not productive, and not a prudent use of customer dollars.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT focused on achieving the reliability benefits outlined in the SAR.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

See our response to Q1 and Q2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to Q1 and Q2.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
As noted in question 2 above, for EOP-011-4, BPA recommends a longer, phased in approach, similar to PRC-005 (PSMP) or PRC-002 (Equipment Monitoring). This would include a timeframe to identify loads and an additional timeframe to design, schedule, and install any required elements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed your suggested changes to the Implementation Plan and determined it is not necessary to make these changes, since the DPs, UFLS-only DPs, and TOs should have sufficient time to make any necessary adjustments to their Load-shed program with the timeframes already specified in the Implementation Plan.	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	

Reclamation recommends 36 months for existing and 60 months for implementation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed your suggested changes to the Implementation Plan and determined it is not necessary to make these changes, since the DPs, UFLS-only DPs, and TOs should have sufficient time to make any necessary adjustments to their Load-shed program with the timeframes already specified in the Implementation Plan.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
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 the implementation timeframes proposed by the SDT.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
As noted in our response to Q1 we believe the drafting team should consider providing TOPs the flexibility to work with entities that are subject to R8 and allow an extension of the 30-month initial implementation period when justifiable conditions warrant.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
No Additional Comments	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
While the NAGF believes that a shorter implementation period would be better for TOP-002 R8, the NAGF supports the proposed implementation plan in order to get the changes made. Once the standard is approved, it would be very beneficial to see Balancing Authorities begin to implement this requirement as soon as possible to reduce the likelihood of another event impacting grid reliability similar to Winter Storms Uri and Elliott due to load forecast errors and unplanned generator outages/unavailability.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. While the Implementation plan is unchanged, the SDT agrees that an expedient implementation is in the best interest of grid reliability.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the proposed implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM and TNMP support the proposed implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	

Answer	Yes
Document Name	
Comment	
It is not clear what the intent of requirement 2.2.8 is and whether this requires exclusion of natural gas infrastructure loads only during extreme cold weather periods? If this is a requirement, a 30 month implementation of such a system requirement may be more technically challenging and take a longer period of time to implement.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. In the second ballot, the SDT discussed whether the exclusion of critical natural gas infrastructure loads as Interruptible Load, curtailable Load, and demand response should be limited to certain situations or be a complete prohibition. The SDT has limited the exclusion of these loads from Interruptible Load, curtailable Load, and demand response only to periods of extreme cold weather as identified in the SAR. Entities should note that the proposed Standard represents a minimum requirement which can be exceeded by individual entities if deemed appropriate.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Unlike other revised obligations, R7 is not specifically mentioned in the proposed implementation plan, inferring that it would become effective “six (6) months after the effective date.” AEP requests clarity from the SDT if our understanding is correct or not.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The portions of EOP-011 not specifically identified with longer implementation timeframes are intended to be effective six (6) months after regulatory approval, which is the effective date of the standard.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the proposed implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

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

Thank you for your comment.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
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	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
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	

Matt Lewis - Lower Colorado River Authority - 1	
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	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
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; Terry Gifford, 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	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 1, 6, 5; Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, 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	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
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	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
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	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 3, Hargrove Donald
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
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	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	

Answer	
Document Name	
Comment	
We support the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

7. Provide any additional comments for the SDT to consider, including the provided technical rationale document, if desired.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
WEC Energy Group has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mike Magruder - Avista - Avista Corporation - 1	

Answer	
Document Name	
Comment	
We support EEI's submitted comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	
Document Name	
Comment	
The term "automatic load shedding" appears in requirements 1.2.5, 1.2.5.2, 2.2.9, 8.1, and 8.1.2. This term is more narrowly scoped as pertaining to UFLS and UVLS in requirements 1.2.5.3, 1.2.5.4, 8.1.3, and 8.1.4. The term "automatic load shedding" should be replaced with "UFLS or UVLS" in each location that it appears in EOP-011-4 to provide additional clarity and consistency.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. These changes have been incorporated in the final ballot.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	
Document Name	

Comment	
EOP-011-4 R1.2.5.5 should be removed and the requirement "Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES" be a DP only responsibility (R8.1.5.). The DP's are responsible to make these provisions in their load shedding plan which they are required to submit to the TOP. The TOP should have no responsibility to make provisions to identify and prioritize these loads itself as they do not have this information.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT has reviewed this comment and determined that the responsibility is correct.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
Part 8.2: As the definition for "reserve margin" varies dramatically across regions, MISO recommends using the term "reserves" instead as detailed below: **8.2** A methodology to determine adequate reserves during the extreme cold weather period…"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT believes the current wording is correct.	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	

Document Name	
Comment	
Reclamation observes that the nature of the cold weather modifications to reliability standards is not cost or time effective and is disruptive to the industry. The first round of cold weather modifications are not effective yet and already modifications for the third round are in progress. Reclamation recommends that an effort be made to offer a first-time quality product instead of multiple revisions on documents that are not even in effect.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT is responding to FERC orders.	
Michael Jones - National Grid USA - 1	
Answer	
Document Name	
Comment	
RE: EOP-011-4 Section C. Compliance, Section 1.2 Evidence Retention: Please consider if R8 should reference "Load shedding plan" instead of "Operating Plan(s)" for consistency with requirement R8. Also, please considering referencing R8 instead of "Requirements R8 and." RE: TOP-002-5 and EOP-011-4 Section C. Compliance: Please consider if there should be consistent use of the abbreviation "(CEA)" noting the difference in Section C. Compliance of TOP-002-5 vs. EOP-011-4.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The SDT has reviewed and updated the Compliance Section.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP is concerned by R1.2.5.2's "circuits that serve designated critical loads which are essential to the reliability of the BES" as well as R8.1.2's "Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES." The Transmission Operator lacks the insight-of, and visibility-into, fuel supply chain (regardless of fuel type) when the supply infrastructure is connected to traditional distribution voltage class. Transmission Operators have tools to determine if an electrical facility outage creates critical problems in their portion of the BES and can further study potential solutions which may include load shedding. It would not seem reasonable that a gas supplier would be capable of performing such an analysis on the electric system since they do not have the tools or the intimate knowledge of the electric grid topology. Likewise, Transmission Operators do not have intimate knowledge of the gas infrastructure or tools to study the impact of a loss of an electric feed to a gas facility. In addition, driven by market or cyber security concerns, there may be a reluctance to share information. It is important to note that Transmission Owners serve multiple distribution providers with connections or service to fuel supply infrastructure, making the needed insight even more lacking. While well intentioned, we believe adding "essential to the reliability of the BES" is a step back in clarity, and it is not clear exactly how such a determination could be made given the limited visibility. AEP requests that the SDT provide insight into exactly what is meant by this phrase as well as how such determinations should be made. In addition, R8's sub bullets which include "which are essential to the reliability of the BES" would require the Distribution Provider to make a determination that we do not believe they would have the insight to make. While AEP has chosen to vote Negative, AEP would be in a better position to vote Affirmative in future ballot periods if the SDT either a) removed the references "essential to the reliability of the BES" entirely, or b) revise the phrase to state "which may have a negative impact on the reliability of the BES as defined by the Distribution Provider, UFLS-Only Distribution Provider, or notified Transmission Owner *in working with the Reliability Coordinator or other applicable regulatory authorities.*" "30 months" is referenced within the proposed revisions, however AEP requests that it be revised to instead state 30 *calendar* months.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	

Thank you for your comments. The SDT has reviewed the wording of R1 and debated whether “essential to the reliability of the BES” is a necessary statement. The SDT included this language based on previous industry comments to ensure there is not an overly broad interpretation of critical natural gas infrastructure loads such that loads would be identified that are not impacting BES reliability. The SDT has clarified the 30 months to 30 calendar months.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Diana Torres - Imperial Irrigation District - 1,3,5,6	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	
Document Name	
Comment	
In general, the EOP-011 stated purpose is to address the effects of operating Emergencies (why is Emergencies capitalized, it is not in the NERC Glossary, should this be an operating Emergency or an operating BES Emergency?) but 1.2.6 specifically focusses on Cold weather and Extreme weather, neither of which is included in the NERC Glossary of Terms, only Extreme Cold Weather is in 2.2.8 (not capitalized). Is this different than 1.2.6.1 and 1.2.6.2? Is Extreme Cold Weather a subset of Extreme weather conditions? There are other situations where an energy emergency, possibly not due to cold weather and extreme weather conditions could result in similar effects. Should 1.2.6 refer to an Energy Emergency with references to those possibly caused by extreme weather conditions such as Extreme Cold Weather (outside of expected design temperatures) or extreme heat (Extreme Heat) causing increased load etc.? A BES Emergency causing loss of load, which also could impact natural gas infrastructure could have a similar effect to the reliability of the BES. Under 2.2.8, does this mean that this is only applicable to extreme cold weather (not capitalized) periods, which is not identified under 1.2.6.1, and is this meant to be armed only during extreme cold weather conditions? Would this apply to any energy emergency including extreme heat where critical natural gas loads are essential to the reliability of the BES? The reference to extreme cold should be removed from 2.2.8. For 2.2.10, similar comments to 1.2.6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT is limited by the SAR to address only certain extreme cold weather impacts to BES. If there are additional circumstances which could negatively impact BES reliability, a new SAR should be filed so they can be investigated, and standards can be amended as necessary. The SDT did review the use of “Emergency” and maintains it is consistent and correct.	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	

Document Name	
Comment	
We support the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	
Document Name	
Comment	

AZPS has no additional comments at this time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
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; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	
Document Name	
Comment	

Tacoma Power continues to have concerns about EOP-011-4 R1 and R2, as described below.

Reliance on non-NERC Registered Entities

The Reliability Guideline cited in the Technical Rationale proposes that electric transmission and distribution owners reach out to regulatory entities, natural gas companies and organizations, and secondary fuel suppliers. Reaching out to this many organizations and agencies, as well as receiving their responses, may be unattainable in the proposed implementation timeline and will be difficult to maintain the coordination. These organizations are not subject to NERC Standards and as a result, may not respond or prioritize coordination with TOPs. Tacoma Power recommends utilizing a note similar to CIP-013 R2 to address this concern. This note should specify compliance with R1.2.5.5 does not include the natural gas companies' or fuel suppliers' performance and adherence to the TOP requests. Example language to add after EOP-011-4 R1 or to the Measure M1: "Note: The following issues are beyond the scope of Requirement R1: 1) the natural gas companies' or secondary fuel suppliers' performance and adherence to TOP request(s) for information on critical natural gas infrastructure, and 2) accuracy of the information provided by these entities."

Avoiding Overlap Between UFLS and Manual Load Shedding

Rather than avoiding an overlap between UFLS and manual load shedding, the Standard should allow for a pro-rata share of UFLS armed load to be shed during other kinds of load shedding. The recent NERC Lesson Learned Report LL20220301 includes a detailed explanation of the problems that can occur when overlap is minimized.

With the current proposal, there are two main problems with requirement R1.2.5.3 and R8.1.2 to minimize overlap between UFLS and other load shedding:

1. When a significant amount of manual load shedding occurs without shedding any UFLS armed load, the proportion of load armed for UFLS increases. Unfortunately, excessive portions of load armed for UFLS can result in system instability.
    - For example, if a utility has 40% of load armed for UFLS and then they shed 20% of the non-UFLS load, the remaining portion of load armed for UFLS jumps to 50%. If an underfrequency event were to occur with 50% of load armed, it is possible that too much load would be shed, resulting in over frequency tripping of generators.
2. The standard requires having provisions, but it does not require that the provisions are actually effective. This is an example of evaluating compliance paperwork rather than evaluating actual system performance.

One possible way to monitor the pro-rata arming of UFLS load is for utilities to monitor in real time that they have adequate UFLS load shedding armed. Although implementing real-time monitor could be a significant effort for some utilities, this would have benefits for verifying that adequate load is armed for UFLS throughout the whole year. On Tacoma Power's system, the total percent of armed UFLS load is extremely dependent on the time of day and season. Tacoma's portion of load armed for UFLS varies from a minimum of 24% in June to a maximum of 42% in February.

Allowing for pro-rata overlap between UFLS and manual loads significantly increases the customer equity during manual load shedding. Under the current standard we have roughly 40% of our customers exempt from rolling blackouts due to being armed for UFLS, plus another 10% designated as critical for other reasons. This forces the remaining customers to have twice as much outage duration as would otherwise be fair.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT discusses many of these concerns in the technical rationale. The SDT does not intend for EOP-011 compliance to prevent utilities from managing their load shedding process to maximize reliability.

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	
Document Name	

Comment	
The coordination efforts between multiple DPs in multiple TOs' areas and the staffing needed to create plans and processes and then implement and manage these plans will be burdensome and costly to the TOPs, DPs and TOs. For EOP-011, Seminole proposes a 36-month implementation time frame. The coordination and agreements between multiple DPs and multiple DPs in multiple TOs' areas could possibly take a significant amount of time. For TOP-002, Seminole proposes an 18 month implementation time frame to remain consistent with other revisions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The team believes that the 30-month implementation time frame for EOP-011-4 (Part 1.2.5, 2.2.8 and 2.2.9) is sufficient for budgeting, acquiring, and installing new physical equipment. The team is proposing an 18-month implementation time frame for TOP-002-5.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends there be a requirement for the TOP to approve the Load shedding plans in receives in EOP-011-4 Requirement R8. Texas RE noticed the Evidence Retention section in TOP-002-5 does not include a retention timeframe specifically for Operating Plans. The section does specifically mention voice recordings, operating logs, and email records, but not Operating Plans. Texas RE recommends specifying a retention timeframe for Operating Plans.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. The SDT does not believe that the TOP is in a position to approve a load shedding plan that they receive. The Evidence Retention section of TOP-002-5 has been clarified based on your comments.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments.	
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	
NPCC RSC supports the drafting team proposal.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	
Document Name	
Comment	
The TO does not supply load and is only responsible for ownership and maintenance of Transmission Facilities (see Appendix 5B - statement of Compliance Registry Criteria (Revision 7) of the NERC Rules of Procedure). Requiring the TO to have a load shedding plan is a flawed concept and assumes an operational function. The TOP, BA, LSE (now obsolete) and DP are the only entities that have control of load. A TO manages assets, and may be directed by the TOP (whose footprint it resides in) to open or deenergize assets under its control for the purpose of shedding load when the TOP does not have direct supervisory control over those assets. What if 1) The TO declares that they have no way to properly shed load under their registration; or, 2) The TOP identifies a TO is required to assist, yet the TO has no operational staff or facilities to assist?	

The Drafting Team may feel this would work out in application, however, once a requirement like this is approved, there will be concern that the TOP may have expanded authority over a TO's organization structure and functional obligations. This will put the smaller organizations at risk.

Lastly, "Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area" is not identified as an entity needing NERC registration under the ROP (Appendix 5B). Is it the drafting team's intent to require these DP entities to be identified and registered under NERC's ROP? How will R8 be enforced against the DPs who are not registered?

We think by expanding the applicability to TO and DP entities the Drafting Team has overstepped its authority. We believe that the standard should stop at the TO, RC and BA levels. In doing so, it would still meet the intent of the BOD resolution. Should the Drafting Team still feel strongly that the expansion of Applicability is warranted, then the ROP may have to be modified to address the additional scope.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT is of the opinion that the currently proposed standards are within the existing NERC framework.

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

Answer	
Document Name	

Comment

No Additional Comments

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	
Document Name	
Comment	
OPG supports NPCC RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
See Comments Submitted by the Edison Electrical Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	

NA	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4	
Answer	
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
For the proposed EOP-011-4, we question the addition of “which are essential to the reliability of the BES” in association with “designated critical loads” (see R1, Part 1.2.5.2; R8, Part 8.1.2). As noted in the Technical Rationale for EOP-011-3, that drafting team associated critical loads with “certain critical loads which may be essential to the integrity of the electric system, public health, or the welfare of the	

community." By adding the phrase "which are essential to the reliability of the BES" to these requirements in the proposed EOP-011-4, this drafting team seems to be eliminating loads deemed critical to public health and the welfare of the community. Was that the intent?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The scope of the SDT work is limited to extreme cold weather by the SAR to address BPS reliability.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
The coordination efforts between multiple DPs in multiple TOs area and the staffing needed to create plans, process, implement and manage is burdensome and costly to the TOPs, DPs and TOs. For EOP-011, propose 36 months implementation. The coordination and agreements between multiple DPs and multiple DP's in multiple TOs areas, could possibly take a significant amount of time. For TOP-002, propose 18 months to remain consistent with other revisions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The team believes that the 30-month implementation time frame for EOP-011-4 (Part 1.2.5, 2.2.8 and 2.2.9) is sufficient for budgeting, acquiring, and installing new physical equipment. The team is proposing an 18-month implementation time frame for TOP-002-5.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	

Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Michael Whitney - Northern California Power Agency - 3	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	
Document Name	HHWPScreenshot_Example of upload to RCWestPortal_OPA.pdf
Comment	

Regarding TOP-002-5 R3 – Can uploading to the RC West site and adding that entity to the affected parties count? (See uploaded screenshot.) This is upon positive knowledge that the affected entity has access to the site.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Requirement R3 is out of scope of this effort. We encourage you to reach out to your auditing agency for clarification on compliance.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	
Document Name	
Comment	
As detailed in its response to question 1, above, the SRC recommends that the term “automatic Load shedding” be replaced with “undervoltage Load shedding or underfrequency Load shedding” throughout EOP-011-4. The term “automatic Load shedding” encompasses more than just UVLS or UFLS Load shedding. Specifically, it may be interpreted to include other frameworks that may involve automatic load Shedding, such as Remedial Action Schemes (which are addressed by PRC-012-2), that are not necessarily used to assist with the mitigation of operating Emergencies and are therefore outside the scope of EOP-011-4. As further detailed in comments submitted in response to draft 1 of TOP-002-5, the SRC continues to believe that the most effective method of accomplishing the objectives of TOP-002-5 involves a requirement for GOs and GOPs to provide appropriate information to BAs. However, in light of the approach the SDT has chosen to pursue, the SRC recommends that requirement R8, part 8.3 of TOP-002-5 be revised to require a three-day forecast instead of the proposed five-day hourly forecast. A three-day forecast would be more accurate and useful for BAs and would reduce the amount of additional data that BAs would need to receive from GOs and GOPs when compared to the proposed five-day hourly forecast. Additionally, producing an hourly forecast, regardless of whether it covers three days or five, would be extremely	

burdensome without a commensurate reliability benefit, especially given the existing BA workload during extreme cold weather periods. The SRC therefore recommends removal of the requirement that the forecast be an hourly forecast. This would allow the BA the flexibility to determine and produce the type of three-day forecast that will be most beneficial to reliability without being unduly burdensome. The SRC also recommends that requirement R8, part 8.3.2 be removed from the standard, as the additional administrative burden of including interchange scheduling in the forecast methodology would not produce a sufficient associated reliability benefit.

The SRC reiterates its recommendation from its comments on draft 1 of EOP-011-4 that requirement R2, part 2.2.8 be revised to apply to **known** critical natural gas infrastructure loads. The SRC recognizes that it is not the drafting team's intent for Responsible Entities to be held responsible for unknown critical natural gas infrastructure loads, and the SRC believes that this revision would clarify that intent.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT has replaced "automatic Load shedding" with more specific wording to avoid this misinterpretation.

Additionally, the SDT discussed the issue of data specification, and in consultation with NERC, determined that all information required by the BA to perform its analysis is available under TOP-003. The current requirements in TOP-003 express the minimum required, however, the language "but not limited to" provides the avenue for the BA to obtain additional data points required to perform real-time assessments and real-time monitoring and other analysis required under TOP-002.

The SDT has debated the benefits of a five-day forecast versus a three-day forecast. The intent of the forecast is to ensure that entities have ample time to prepare units for operation when extreme cold weather is forecasted.

The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality.

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District,

3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	
Document Name	
Comment	
SMUD and BANC support the comments submitted by Tacoma Power regarding "Avoiding Overlap Between UFLS and Manual Load Shedding".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	