Comment Report

Project Name:	2023-07 Transmission Planning Performance Requirements for Extreme Weather | Draft 4
Comment Period Start Date:	11/7/2024
Comment Period End Date:	11/21/2024
Associated Ballots:	2023-07 Transmission Planning Performance Requirements for Extreme Weather Implementation Plan AB 4 OT 2023-07 Transmission Planning Performance Requirements for Extreme Weather TPL-008-1 AB 4 ST

There were 50 sets of responses, including comments from approximately 140 different people from approximately 89 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The Drafting Team (DT) updated Requirement R2 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

2. The DT updated Requirement R9 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

3. The DT updated Attachment 1 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

4. The DT believes proposed modifications in TPL-008-1 provide entities with flexibility to meet the reliability objectives 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.

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

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

					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO
					Joshua Phillips	Southwest Power Pool	2	MRO
					Patrick Tuttle	Oklahoma Municipal Power Authority	4,5	MRO
Exelon	Daniel Gacek	1		Exelon	Daniel Gacek	Exelon	1	RF
					Kinte Whitehead	Exelon	3	RF
Independent Electricity System Operator	Helen Lainis	2		IRC SRC	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Charles Yeung	SPP	2	SERC
					Elizabeth Davis	PJM	2	RF
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
Public Utility District No. 1 of Chelan County	Joyce Gundry	3		CHPD	Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Diane Landry	Public Utility District No. 1	1	WECC

						of Chelan County		
					Tamarra Hardie	Public Utility District No. 1 of Chelan County	6	WECC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Travis Grablander	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC

					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC

					Erin Wilson	NB Power	1	NPCC
					James Grant	NYISO	2	NPCC
					Michael Couchesne	ISO-NE	2	NPCC
					Kurtis Chong	IESO	2	NPCC
					Michele Pagano	Con Edison	4	NPCC
					Bendong Sun	Bruce Power	4	NPCC
					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
Shannon Mickens	Shannon Mickens		MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Mia Wilson	Southwest Power Pool Inc.	2	MRO
					Eddie Watson	Southwest Power Pool Inc.	2	MRO
					Erin Cullum	Southwest Power Pool Inc.	2	MRO
					Jonathan Hayes	Southwest Power Pool Inc.	2	MRO
					Jeff McDiarmid	Southwest Power Pool Inc.	2	MRO
					Scott Jordan	Southwest Power Pool Inc	2	MRO
					Mason Favazza	Southwest Power Pool Inc	2	MRO
					Zach Sabey	Southwest Power Pool Inc	2	MRO
					Josh Phillips	Southwest Power Pool Inc.	2	MRO
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

1. The Drafting Team (DT) updated Requirement R2 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	

BC Hydro appreciates the drafting team's efforts and opportunity to comment, and offers the following comments.

(1) The ERO is not subject to TPL-008-1 regulatory compliance. Entities are relying on the ERO's infrastructure and commitment to maintain the benchmark temperature event library. As drafted, a PC can be in a potential noncompliance if they choose to use a benchmark event from the ERO-maintained library, and the event is not meeting the specifications per Parts 2.1 and 2.2.

BC Hydro is requesting that the drafting team in conjunction with the ERO document the controls that will be in place to maintain the library. These controls should include the location of the library and quality checks to ensure the events in the library meet R2 Parts 2.1 and 2.2.

BC Hydro recommends revising the language of R2 Parts 2.1 and 2.2 to apply if a PC develops their own benchmark events, and not apply to the ERO benchmark events library.

(2) A Planning Coordinator may be in a potential noncompliance if another PC is not participating in the required coordination and assessment activities, which may be the case as different jurisdictions (such as Canada and US, or even between BC and Alberta within Canada) have different standard adoption timelines.

BC Hydro suggests that the Implementation Plan include provisions that allow for compliance enforcement only when TPL-008-1 is effective in all applicable jurisdictions.

Alternatively, the Canada West zone should be split into a BC-only zone. This may help alleviate compliance risks and it will also help creating a more robust ETA given the different geographic areas and weather zones across the Canadian provinces of BC and Alberta.

There could also be scenario where in a multiple PC zone there may one PC that does not participate in the coordination, or there is no agreement on a common event. In such a scenario, all PCs may be found in noncompliance.

BC Hydro recommends that the standard include provisions to allow for conflict resolution.

Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	

NextEra does not agree with the modifications to R2. The SAR references the use of either “a projected frequency (e.g., 1-in-50-year event); or a probability distribution (95th percentile event).” The development of extreme events refers to foot note 9 *“Benchmark events will form the basis for a planner's benchmark planning case— i.e., the base case representing system conditions under the relevant benchmark event—that will be used to study the potential wide-area impacts of anticipated extreme heat and cold weather events.”*

FERC via the SAR requested to develop a base case that is representative of system conditions which could be a 1 in 50 year or a P95 event. Following the proposed language in the standard and the ERO library, the warmest temperature Florida could use for its winter assessment is 32.3 degrees and the lowest being 24.9F. The concern is that the entire state is at freezing temperatures and will generate significant winter loads in Florida much larger than the 20% sensitivity we use for winter, thereby generating transmission projects that will not provide value to our customers. NextEra does not consider this a P95 event, especially if the average 3 rolling day is taking into consideration (also not requested by the SAR). The coldest temperature experienced in Miami over the last 40 years was during the winter of 1989, where temperatures were as low as 30 degrees. The lowest 3 day rolling average was 32.6 degrees (12/23-27F, 12/24-31F, 12/25-30F and 12/27-38F). The standard as written will force NextEra to plan to a greater than P100 winter loads. This is an un-realistic approach, considering most of Florida’s load is located in Southern Florida south of Lake Okeechobee. NextEra recommends the language in R2 to state “Represent the 95th percentile extreme conditions for the climate zone based on the 3-day rolling average of maximum (heat) or minimum (cold) temperature across the zone.”

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

R2.2, "Represent one of the 20 most extreme temperature conditions based on the three-day rolling average of daily maximum (heat) or daily minimum (cold) temperature across the zone," is far too lax. Selecting the 20th most severe event of the past four decades would not constitute much of a challenge.

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC (CEHE) believes with the current zone designations, there are some zones where temperature differences would be significant due to their very large north/south geographical spans. A concern arises whether the chosen extreme temperature event case is applicable to the overall zone in these cases. It might not be representative of certain parts of the zone. Transmission Planners should be involved in

the selection. CEHE recommends the following revision: Each Planning Coordinator**, in conjunction with its Transmission Planner(s)**, shall select which extreme heat and extreme cold weather events to develop benchmark extreme temperature events applicable to their region.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	No
Document Name	
Comment	

SPP opposes splitting our region into North and South zones. As a contiguously integrated system, our system does not demarcate at state lines boundaries. We recently completed our 2024 Integrated Transmission Plan that resulted in $7.5B in network upgrades to further strengthen this integration.

The standard as written could require SPP to select a high and low temperature extreme in both the northern region and southern region, creating a situation where we are disconnecting the interconnections we built and those planned to in the future. This results in a needless complication to the existing systems and creates an unnecessary burden that does not improve reliability. As proposed in the previous version of the document, we request the Planning Coordinator zone be reestablished into a contiguous system for evaluating these extreme events. The bifurcation is even less appropriate when considering the events proposed in the *ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance* indicate using an event that overlaps both SPP regions from December 24, 1989. Conversely, the proposed extreme heat case only affected the proposed SPP South Region.

If required to use two zones, we would like to see clarification in the language that indicates regions are allowed to utilize the same scenario provided it meets the requirements in 2.1 and 2.2.

Likes 0	
Dislikes 0	

Response

Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	

We have some comments / observations regarding Req #2 that we would like to share with the SDT:

- In Req #2 language, the word ‘select’ has been replaced by ‘identify’. However, we observe that the word ‘select’ is still utilized in the Measure #2 language, the Req #3 language and in the Technical Rationale document. This inconsistency could cause some confusion about the actual intent.

For example, the word ‘identify’ might better imply the coordination that is allowed by Req #2.

The Technical Rationale should be updated to highlight and clarify the significance of this wording change.

- Req #2 states that the benchmark temperature events shall be obtained from the benchmark library maintained by the ERO or developed by the Planning Coordinators. Is this implying that some of the benchmark events may not be available on the library after they are developed by the PCs? If so, is there any expectation (or should there be any) that these benchmark events be somewhat communicated/shared to other PCs for awareness if they are developed and not on the benchmark library?

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	Yes
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

FirstEnergy has no concerns with the update to Requirement R2.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE recommends revising Measure M2 from "…to select one common extreme heat benchmark temperature event" to "to identify one common extreme heat benchmark temperature event. This makes the language consist with the revision made to Requirement R2.	
Likes 0	
Dislikes 0	
Response	

Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Southern Company supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC supports the proposed changes made to Requirement R2.	
Likes 0	
Dislikes 0	
Response	

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

Document Name	
Comment	
EEI supports the changes made to Requirement R2, which empowers the Planning Coordinator to develop the benchmark temperature events rather then solely depending on the benchmark temperature events contained in the benchmark library.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM & TNMP supports EEI's comments and supports R2.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirement R2. Additionally, are there any plans to add guidance regarding "most extreme temperature conditions" in section 2.2? Can a planning coordinator come up with its own criteria/metric considering that they are likely a broad range of temperatures throughout the weather zone(s) for each temperature events?	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes

Document Name	
Comment	
Ameren agrees with EEI's comments.	
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	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	

See EEI Comments

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 1

Likes 0	
Dislikes 0	

Response

Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC

Answer	Yes
Document Name	

Comment

The ISO/RTO Council Standards Review Committee (IRC SRC) generally agrees with the revisions to Requirement R2, and recommends the following additional revisions to further clarify the Requirement:

- Revise the second-to-last sentence at the end of R2 as follows to reference PCs first and the ERO benchmark library second to avoid a possible inference that the PC is required to develop its own benchmark library:

“The benchmark temperature events shall be developed by the Planning Coordinators or obtained from the benchmark library maintained by the ERO.”

- Revise the last sentence at the end of R2 to read as follows to better reflect the fact that the Planning Coordinator (rather than the benchmark temperature event) is ultimately the entity making the considerations described in Parts 2.1 and 2.2: “**The Planning Coordinator’s selection of** each benchmark temperature event shall:”

- Revise Part 2.2 as follows to clarify that the temperature conditions referenced in Part 2.2 are required to fall within the time period referenced in Part 2.1: “Represent one of the 20 most extreme temperature conditions **within the period identified in Part 2.1** based on the three-day rolling average…”

Likes 0	

Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) for this question and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
AEPC has signed on to ACES comments. Please review ACES comments.	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
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	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
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	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
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	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
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	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
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	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
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

Carver Powers - Utility Services, Inc. - 4

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

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	

2. The DT updated Requirement R9 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	

Comment

The current language in R9.4 says revisions to Corrective Action Plans are limited to the subsequent Extreme Temperature Assessments, yet the underlying system may have change identified through system upgrades. These Corrective Action Plans should be more flexible in the event a system upgrade is completed or a separate assessment demonstrates the underlying performance issue has been mitigated. The inclusion of “or other planning assessments” in 9.4 appeared amicable during the drafting team discussion, and we request this be adopted as proposed in the following revision:

9.4. Be permitted to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments **or other planning assessments**, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1.

Likes 0	
Dislikes 0	

Response

Mark Flanary - Midwest Reliability Organization - 10

Answer	No
Document Name	

Comment

MRO is not confortable with two parts of R9.3, both of which limit signicantly the region's ability to meaningfully enforce the requirement:

1. The terms “regulatory authorities” and “governing bodies” are not specific

2. There are no timning requirements prescribed for the responsible entity concerning when the responsible entity must make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	
Comment	

ERCOT joins the comments submitted by the IRC SRC for this question and adopts them as its own.

Likes 0	
Dislikes 0	
Response	

Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC

Answer	No
Document Name	
Comment	

The current language in R9.4 says revisions to Corrective Action Plans are limited to subsequent Extreme Temperature Assessments. However, the underlying system may change between assessments because of system upgrades. These Corrective Action Plans should be more flexible in the event a system upgrade is completed or a separate assessment demonstrates the underlying performance issue has been mitigated. The inclusion of "or other planning assessments" in 9.4 appeared to be acceptable during the drafting team discussion, and we request this be adopted as proposed in the following revision:

a. 9.4. Be permitted to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments **or other planning assessments**, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1.

Likes 0	
Dislikes 0	
Response	

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	
Comment	

The current draft is not clear what the timeframe is for providing the CAP in R9.1. In addition, there is no timeframe when to notify the applicable regulatory authorities or governing bodies in R9.2. CEHE strongly disagrees with the following statement in R9.3: "Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues." CEHE recommends that "applicable regulatory authorities or governing bodies" be defined. CEHE also recommends that TPs should be providing CAP information only to their PC.

Likes 0	

Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
NextEra does not agree with the language of R9.3 regarding the solicitation of feedback, as this is in line and satisfied through R11 of the standard.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
During the recent revisions, a proposal was made with support to clarify 9.4 that revisions to a Corrective Action Plan should be allowed if other planning assessments resolve the concern. As such this should be captured in requirement 9.4 such as the following: 9.4. Be permitted to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments **or other planning assessments**, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1.	
Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
• The purpose and required response actions related to the sharing of CAPs and solicitation of feedback is not clear. • Documentation of alternatives is an additional administrative burden and provides little benefit to reliability. It is also unclear if there is some type of expectation these alternatives are reviewed or potentially challenged as invalid.	

- The role of the TO and/or GO in implementing or otherwise responding to CAPs that may require additions or modifications to their systems/facilities is not captured in these requirements.
- There appears to be a significant amount of outside review required but no clear actions the responsible entity is required to take, particularly if there is a dispute. What is the purpose of the review and the expected response? This potentially produces an undue burden on the PC/TP and adds subjectivity in requiring a review with no documented guidelines for conducting the review.
- GTC recommends the restructuring of requirement 9 such that documentation of alternatives along with the sharing and soliciting feedback back is only necessary when utilizing Non-Consequential Load Loss as an interim solution.

Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1, Group Name Eversource

Answer	No
Document Name	

Comment

Eversource has concerns regarding compliance with Requirement R9.3. Because this standard is focused on “Extreme Temperature Events”, the company can foresee issues with regulatory agencies not wanting the company to invest significant funds into these issues. What would occur if Eversource supplied a CAP to the appropriate governing body and they state they do not agree the work is necessary? Would creating the CAP still meet the intent of the requirement although it may not be allowed to be implemented? Eversource recommends the DT consider adding language in case such a scenario arises.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

We recommend that further clarification be given to how “applicable” regulatory authorities or governing bodies are determined.

Likes 0	
Dislikes 0	

Response

Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton

Answer	No
Document Name	
Comment	

Oncor strongly disagrees with the following statement in R9.3: “Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.” We propose that “applicable regulatory authorities or governing bodies” be defined and limited. For example, a TP should only need to provide their PC with CAP information.

Likes 0	
Dislikes 0	
Response	

Carver Powers - Utility Services, Inc. - 4

Answer	Yes
Document Name	
Comment	

1) Based on other projects that include developing and implementing CAPs, USV does not agree with the proposed modifications and would feel more confident if there were guidelines and more structured timelines set for the CAPs. Perhaps not in the standard itself, but guidance on timelines could be explained in the technical rationale and include timelines for implementing CAPs and when entities can utilize backup action plans such as Non-Consequential Load Loss.

2) The newly proposed modifications to R9 compared to the proposed modifications from the previous draft do not change the obligations for responsible entities. The new requirement 9.3 is administrative in nature and does not appear to provide any increase in reliability, if anything it would delay the implementation of the CAP. USV understands the directives in FERC order 896 and the need for R9. However, we disagree that any significant improvements have been made to previously proposed R9 modifications.

Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 2

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

See EEI Comments

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

Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop

Answer	Yes
Document Name	

Comment

Ameren agrees with EEI's comments.

Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirements R9.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM & TNMP agrees with R9.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the changes made to Requirement R9 and offers no additional changes.	
Likes 0	
Dislikes 0	

Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC supports the proposed changes made to Requirement R9.	
Likes 0	
Dislikes 0	
Response	
Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Southern Company supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no concerns with the update to Requirement R9.	
Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
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	
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	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 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	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3,	

6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	

Comment	
Texas RE continues to recommend including a timeframe for which the CAPs need to be developed and implemented once the benchmark planning case study results indicate the System is unable to meet performance requirements. Requirement R2 states: “Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted for category P0 in Table 1, in for situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in *the required timeframe*…” Texas RE reads the proposed standard language as allowing the entity to determine the “required timeframe.” While the revised language provides for a coordination process with regulatory authorities, it does not appear these entities could reject a Corrective Action Plan if the required timeframe was unduly extended. Texas RE therefore continues to recommend placing more explicit requirements around CAP development and implementation to prevent unilaterally lengthy CAPs and ensure their timely and effective implementation.	
Likes 0	
Dislikes 0	
Response	

3. The DT updated Attachment 1 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	No
Document Name	

Comment

The SDT made vast improvements to Attachment 1 by splitting MISO and SPP zones into MISO North, MISO South, SPP North, and SPP South. The SDT attempted to move the disjointed sections of SERC Central to the appropriate MISO or SPP zones. However, the SDT needs to include geographical boundaries to clarify which SERC Central PCs should belong to MISO North, MISO South, SPP North, and SPP South. For example:

- Zone - “MISO South”
- Planning Coordinator(s) – “Planning Coordinator(s) in MISO and *SERC* that serve portions of Montana, North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Michigan, Indiana, Illinois, Missouri, or Kentucky”

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

B.C. has a wide geographic area, applying one common extreme temperature is not ideal. The Canada West cold benchmark event temperatures are closer to our BC Hydro south region coldest days temperature. However, as winter peaking utilities, most of BC Hydro’s temperature sensitive load (mostly distribution load) are located in the Lower Mainland and Vancouver Island.

BC Hydro recommends that the Canada West zone be split into BC and Alberta based on weather and geographical differences that are more conducive to a robust ETA.

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No

Document Name	
Comment	

Please view response to Question 1.

Likes 0	
Dislikes 0	
Response	

Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC

Answer	No
Document Name	
Comment	

It is not clear to the IRC SRC whether the current draft addresses temperature variances from east to west of the current zones, not just north to south. For example, entities with a wide east to west territory may have vastly different climates that may need to be split into additional zones.

During the last comment review, the drafting team discussion indicated that a Planning Coordinator with more than one zone may utilize the same weather event. Ideally the drafting team would revert to the contiguous planning coordinator zones. Either way, this understanding, that two zones within a single PC may use the same event, should be documented within the standard to ensure there is no ambiguity should an entity carry out such approach. The IRC SRC would like to see clarification in the language that indicates regions are allowed to utilize the same scenario provided it meets the requirements in 2.1 and 2.2.

ERCOT, IESO, and PJM abstain from IRC SRC response and comments to Q3.

Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	
Comment	

SPP's PC footprint should not be split into northern and southern zones (see question #1).

Likes 0	
Dislikes 0	

Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no concerns with the update to Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
In the attachment 1, remove “WECC” from “WECC Southwest” to match up with the Zones Map.	
Likes 0	
Dislikes 0	
Response	

Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Southern Company supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC supports the proposed changes made to Attachment 1 zones.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the changes made to Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes

Document Name	
Comment	
PNM & TNMP agrees with the changes to Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the updates made to the table and map in Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
There may be only limited value is running dynamic analysis on a Long-Term planning case (i.e. 10 yr out case). And these cases are difficult to build and are often not N-1 secure (meaning not all single contingencies will result in a valid load flow solution). Given this, and the multiple future assumptions, the dynamic portion of the studies may not provide tangible value."	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	

Comment	
Ameren agrees with EEI's comments.	
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	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	

See EEI Comments

Likes 0	
Dislikes 0	

Response

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	Yes
Document Name	Draft 4 Attachment 1 Example.pdf

Comment

The Attachment 1 graphic would greatly benefit from including state boundaries. Please see attached example.

Draft 4 Attachment 1 Example.pdf

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

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	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
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	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
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	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
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	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 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	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	

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	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 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	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	

Answer	
Document Name	
Comment	
Texas RE continues to be concerned that multiple contingencies may not be used to assess the system in extreme temperature events. In Requirement R7, Table 1 only shows single contingencies and double circuit contingencies for assessing steady state and stability performances. Based on the contingencies listed in Table 1, the reasoning for R7 is not clear. Are the responsible entities expected to select single contingencies and double circuit contingencies and use those contingencies to assess the system? During extreme temperature events, multiple overlapping contingencies are expected and frequently occur. Given this fact, the proposed standard should correspondingly require Registered entities to study overlapping contingencies to identify system deficiencies and prepare the mitigation plans.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	
Comment	
During the last comment review, the drafting team discussion indicated that a Planning Coordinator with more than one zone may utilize the same weather event. This understanding should be documented within the standard to ensure there is no ambiguity should an entity conduct such an approach. The MRO-NSRF would like to see clarification in the language that indicates regions are allowed to utilize the same scenario provided it meets the requirements in 2.1 and 2.2.	
Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	

4. The DT believes proposed modifications in TPL-008-1 provide entities with flexibility to meet the reliability objectives 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.

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

Answer	No
Document Name	

Comment

Sensitivity to generation, load and transfers are already studied as part of TPL-001-5.1 yearly for near and long-term scenarios (year 10/year 12). The sensitivity additional studies proposed for R8.2 are unlikely to yield any new information and will be duplicative work for Transmission Planners.

The Extreme Temperature Assessment is already a very extreme sensitivity study itself that should already capture modified load, generation, transmission, and transfers befitting this analysis per R3, so it is not needed nor appropriate to study sensitivities for sensitivity cases. Further sensitivity cases to adjust such power flow variables would be a nice idea, but it does not appear cost effective to mandate developing and evaluating “sensitivity” cases in addition to the already sensitive nature if the extreme weather assessment.

If sensitivity cases are deemed necessary, it would be more cost-effective to waive the obligation to study and analyze stability for those sensitivities.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	

Comment

The changes to the zoning and mapping create an administrative burden with little benefit to the reliability based upon the current language. This requires coordination with ourselves and the proposed event library recommends the same across our entire footprint. This would not be cost effective to create multiple models and sensitivities which would not leverage the transmission system built to support reliability.

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No

Document Name	
Comment	
CEHE believes the new draft TPL-008-1 still imposes a cost and time burden to PCs/TPs without substantial benefits to reliability of BPS. To support this standard CEHE would like to learn more information on any economic analysis that was performed.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
See our comments for Question 1.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
• ITC believes it is not cost effective to build sensitivity models and analyze the required events yet not require any Corrective Action Plans. If these cases have value and justification to be created and analyzed, then the problems generated within them are also justified to need mitigation to assure reliability. • Corrective Action plans utilizing only Non Consequential Load Loss do not provide value regarding reliability objectives. Reliability should aim to maintain service to serve firm load and for single contingencies when it may be critical to end users/load under extreme temperature conditions. Entities would need to proactively start shedding load for changes in generation, real and reactive forecasted Load, or transfers; load shed is not a solution to the problems identified on how to deliver reliable service to load.	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	

Answer	No
Document Name	

Comment

The attempt for flexibility is appreciated but this standard still falls short of something that is clear and allows the PC/TP to appropriately plan to meet reliability goals during extreme temperature events. The inclusion of outside entity reviews of CAPs offers the reviewer flexibility as there are no bounds provided to them. The PC/TP, however, is potentially impacted by subjective reviews that have no framework with which the PC/TP can effectively respond.

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1

Answer	No
Document Name	

Comment

New Standard requiring extensive coordination with adjacent PCs/TPs within the defined "zones". New Standards impose a cost and time burden to PCs/TPs without necessarily providing substantial benefits to the reliability of the BPS.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

This should be part of TPL-001 and not a separate TPL Standard.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	
Comment	
At this time, we are unable to fully agree that this standard provides the necessary flexibility to meet the reliability objectives in a cost-effective manner. We would be interested in more information on any economic analysis that was performed.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no concerns with the cost-effectiveness of this draft.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
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	

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

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
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	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
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	
Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
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	

Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
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	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
NV Energy does not have a comment regarding the cost-effectiveness.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy’s focus is on system reliability and will not respond to the cost effectiveness question.	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	

Answer	
Document Name	
Comment	
Ameren prefers not to comment on the cost effectiveness of the project.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	

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

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	
Document Name	

Comment

HQ supports these revisions.

Likes 0	
Dislikes 0	

Response

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1

Answer	
Document Name	

Comment

Requirement R10 should explicitly clarify that a Corrective Action Plan is not required for P7 Contingencies, as stated in the previous draft 2, Table 2.1, page 11.

R6 VRF is 'High', but it should be set as ‘Medium’ to match TPL-008 R5.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	
Document Name	

Comment

AEP offers the following additional comments regarding potential overlapping or duplicative obligations.

R3 and R4 appear duplicative in that they both involve the formation of study cases. R3 states “Implement a process for developing benchmark planning cases” while R4 states “Use the coordination process… to develop the following… planning benchmark cases.” R1’s “shall complete its responsibilities such that the … assessment is completed…” appears duplicative with R8’s “shall complete steady-state and stability analysis… ”. AEP recommends removing the last sentence from R1 regarding completing the Extreme Temperature Assessment at least once every five calendar years and appending it to R8.

Regarding R5, the TP and PC should already possess steady state voltage criteria to satisfy TPL-001 R5. As a result, AEP recommends removing R5 to avoid compliance risk associated with duplicative obligations. If the drafting team chooses to retain R5, the phrase “shall have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations” might benefit from something more actionable than “shall have.” AEP recommends the drafting team consider “shall devise” or “shall develop.”

R6’s identification of instability, uncontrolled separation, and cascading per criteria or methodology is already required in TPL-001 R6, which once again appears duplicative and would unnecessarily increase compliance risk. AEP recommends it be removed.

Likes 0	
Dislikes 0	

Response

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	
Document Name	

Comment

The below comment was provided previously for R2.

NERC's consultant uses BA load weighting (based on notes and conversations provided in the 9/10 TPL-008 presentation). As a result, this weighting practice does not appear to directly meet this proposed R2.2 language regarding the most extreme events for a region. The temperature may not actually be representative of “across the zone” because of this weighting. Of reliability considerations, load is certainly part of the need, but potential impacts to generation and the connecting transmission, which may be in other regions, are also important pieces to the delivery of resource to load. Removal or modification of this R2 ‘most extreme’ language is recommended; or exempting the NERC library from needing to follow these criteria. Alternately, the SDT may modify to allow weighting to be used in method.

Because the NERC Extreme Weather Event library is only updated every 3 years in the current plan, it is possible that an event in the library would contain events that would not meet these R2 criteria for event “freshness”. The SDT may wish to consider modifying the language regarding time, or an additional clause, to permit events currently in the NERC Extreme Weather Event library to not be subject to the selection criteria currently in R2, or that entities may use the other criteria to evaluate and select other events.

The below comment was provided previously for R3-R4.

In FERC Order 896, paragraph 39, there is a Commission Determination as follows:

“We also direct NERC to include in the Reliability Standard the framework and criteria that responsible entities shall use to develop from the relevant benchmark event planning cases to represent potential weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates) and expected future conditions of the system such as changes in load, transfers, and generation resource mix, and impacts on generators sensitive to extreme heat or cold, due to the weather conditions indicated in the benchmark events. Developing such a framework would provide a common design basis for responsible entities to follow when creating benchmark planning cases. This would not only help establish a clear set of expectations for responsible entities to follow when developing benchmark planning events, but also facilitate auditing and enforcement of the Standard.”

In review of Order 896, we find the term “contingencies” is used two different ways. Paragraph 39 describes things that are in the base or N-0 state – for example, a cold weather event occurs, and certain wind generators can no longer operate – this as a base contingency. Similarly, in paragraph 88, there is an additional Commission Determination as follows, in further support of these baseline “contingency” outages:

“Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events as described in more detail below.”

Then later, in Paragraph 92 (still under the Commission Determination), FERC further clarifies:

“Regarding the comments of NYISO and EPRI on the difference between extreme events and contingencies covered under Reliability Standard TPL-001-5.1, we clarify that all contingencies included in benchmark planning cases under the new or modified Reliability Standard will represent initial conditions for extreme weather event planning and analysis. These contingencies (i.e., correlated/concurrent, temperature sensitive outages, and derates) shall be identified based on similar contingencies that occurred in recent extreme weather events or expected to occur in future forecasted events.”

From these, it is clear that Order 896 is expecting “contingencies” of weather-based equipment outages to be part of the base or N-0 system state. The more traditional “contingencies” are then addressed on top of this condition, as presented in Order 896, Section G, starting at Paragraph 95.

The specific request from this comment is for the SDT to clarify how it expects such base “contingencies” to be included in the model. There does not appear to be language currently in the standard in support of this, and it is clear from Order 896 that it is expected both the base model outage “contingencies” and then subsequent contingency events to test system performance.

The SDT responded to this in its version 3 comment response:

“The SDT drafted Requirement R4 to require the responsible entity to use data consistent with Reliability Standard MOD-032, supplemented by other sources as needed, for developing benchmark planning cases that represent System conditions based on selected benchmark temperature events. This aligns with directives in FERC Order No. 896, paragraph 30, emphasizing the requirement of developing both benchmark planning cases and sensitivity study cases. Requirement R4 is consistent with Reliability Standard TPL-001-5.1 in cross-referencing Reliability Standard MOD-032, which establishes consistent modeling data requirements and reporting procedures for the development of planning horizon cases necessary to support analysis of the reliability of the interconnected System. It is also consistent with Reliability Standard TPL-001-5.1 in acknowledging that data from other sources may be required to supplement the data collected through Reliability Standard MOD-032 procedures.”

The original comment was not related at all to MOD-032 data. FERC is expecting NERC to develop a standard to build extreme weather cases, and as part of those cases, FERC is requiring that in the base N-0 condition also include “weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates)”. The current draft of TPL-008 does not mention outages, de-rates, or generator availability due to extreme weather in its R3 or R4 language. R3.2 simply includes “Forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone.” And R3.3 similar “Assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in areas outside the zone, as needed.”, but language for “weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates)” from Order 896 is absent from the standard in its current form. This language should be added, likely to R3.2 and R3.3 because it conveys powerful root concept of unexpected equipment outages and limitations in the base state due to extreme weather. If it is the SDT’s intention that entities will review Order 896 and conclude that such concurrent outages are to be covered by a ‘supplemented by other sources as needed’ clause, this is not the case. The standard needs to include language for entities to consider how such extreme weather related concurrent/correlated outages are to be included in the base case.

The below comment was provided previously for R9.

In Order 896, FERC’s Commission determination in paragraph 157 reads:

“As stated above, we adopt and modify the NOPR proposal and direct NERC to require in the new or modified Reliability Standard the development of corrective action plans that include mitigation for specified instances where performance requirements for extreme heat and cold events are not met—i.e., when certain studies conducted under the Standard show that an extreme heat or cold event would result in cascading outages, uncontrolled separation, or instability.”

FERC's directive is when the outcome of studies would result in cascading outages, uncontrolled separation, or instability, a corrective action plan is required. However, in TPL-008, the SDT has gone further. The current state of draft TPL-001-8 R9 states:

"Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. For each Corrective Action Plan, the responsible entity shall:"

The difference here is Order 896 is only requiring corrective action plans for cascading outages, uncontrolled separation, or instability. the SDT is proposing to require corrective action plans for not meeting performance criteria, which also includes normal voltage limits or normal line ratings, even though these exceedances may not result in cascading outages, uncontrolled separation, or instability. The request is for the SDT to align its R9 language with Order 896 paragraph 157 language. These other limits are needed to assess for cascading outages, uncontrolled separation, or instability, but the requirement to develop a corrective action plan for such exceedances is beyond Order 896's request for this proposed standard.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

BPA understands the complexities of drafting technically sound standards and appreciates the SDT's efforts through the multiple postings of this project.

Likes 0	
Dislikes 0	

Response

Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton

Answer	
Document Name	

Comment

No Comment

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4	
Answer	
Document Name	
Comment	
The Western Power Pool would like to thank the Drafting Team for working hard to find consensus. We understand the challenges the Drafting Team faces in meeting the expectations of a number of different organzations across North America.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	
Document Name	
Comment	
Requirement 3 – Eversource recommends reinserting "Transmission Planner" or the phrase used in R4 "Each responsible entity, as identified in Requirement R1" as part of the coordination in R3. The DT stated in its Consideration of Comments that "Coordination is at the PC level and not at the TP level." Eversource agrees this to be true for developing the Temperature Events but disagrees in regards to implementing a process for developing planning cases. If the TPs are going to be expected to have a role in completing the Extreme Temperature Assessment as stated in Requirement 1, they should participate in implementing a process for the development of cases. Each Planning Coordinator shall coordinate with all Planning Coordinators **and Transmission Planners** within each of its zone(s)…; or Each Planning Coordinator shall coordinate with all Planning Coordinators and **with each responsible entity, as identified in Requirement R1,** within each of its zone(s)…;	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	

None	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
FirstEnergy has no additional comments.	
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	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE continues to underscore that the Standard Requirements, as currently stated, do not appear to require assessing the impact of concurrent failures of the Bulk Power System generation **and** transmission equipment that are typically experienced during extreme heat or cold weather conditions. FERC Order No. 896 states: "…the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the	

potential for cascading outages that may be caused by extreme heat and cold weather events should be studied". The Considerations of the Order document says "Per Requirement R4, the data necessary to build the benchmark planning cases must be provided via MOD-032 and supplemented by other sources as needed. Any concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark temperature events should be reflected in the model data and thus represented in the initial conditions of the benchmark planning cases."

Based on the current Requirements R3 and R4 language, the cases could be built with high loads and high generation dispatch for the extreme weather without including concurrent outages. Therefore, a requirement in R3 or R4 that specifically says to include "concurrent" generator and transmission outages in the initial conditions of the benchmark planning cases needs to be added in accordance with the FERC Order. Also, the rationale for those concurrent outages selected for the initial conditions shall be available as supporting information. Texas RE noticed that the Technical Rationale does mention concurrent outages and recommends incorporating this language directly into the requirement language itself through the note described below.

Texas RE suggests either requiring the basic assumptions described in R3 to include, at minimum, the severe contingencies or outages experienced within each Transmission Planner's respective area during the most extreme conditions to be modeled in the benchmarking cases. Texas RE recommends the following language for Requirement R3:

3.5 The most severe continencies experienced in each Transmission Planner's respective area during a historical most extreme conditions shall be documented and modeled in the benchmark planning case(s).

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	
Document Name	

Comment

Comments: GTC has provided the below recommendations in previous ballots, however, it appears that the SDT has not considered revising the proposed standard to address, therefore, these concerns/recommendations are still considered valid by GTC.

R4:

• The SDT should consider removing R4.2, since the assessment already covers multiple extreme weather scenarios. There is questionable reliability benefit in running additional sensitivities that do not rise to the level of requiring (or eliminating) corrective actions.

R5:

• The recently adopted NERC Glossary term, System Voltage Limits, should be referenced in this requirement instead of the outdated wording "System steady state voltage limits". "…shall have criteria for acceptable System Voltage Limits …"

• Since this requirement appears to refer to steady-state voltage, the post contingency voltage deviation portion of the existing requirement should be removed. The resultant steady-state voltage level being outside of acceptable high and low limits is the point of concern. For example, if a low voltage criterion is 0.92 p.u., then voltages below this limit would violate this particular criterion regardless of whether the beginning voltage was 0.95 p.u., 0.98 p.u., or any other voltage level.

R6:

• The inclusion of "within an Interconnection" is not appropriate as the PC or TP should not be required to assess outside of its applicable area. Note the inclusion of more appropriate language referring to the PC's or TP's planning area (its portion of the Bulk Electric System) in this draft so it is not clear why some requirements refer to an Interconnection while others, more correctly, refer to the area of actual responsibility for the PC or TP.

• The following bullet contains a wording addition to clarify the applicability of this requirement to System-wide impacts. This is also consistent with wording in other Reliability Standards when referencing these types of impacts.

• "Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology used in the Extreme Temperature Assessment analysis to identify instability, uncontrolled separation, or Cascading of the Bulk Electric System."

R8:

• It is unclear if the responsible entity must identify continencies for each event type shown within each category, or only those event types that are expected to produce more severe System impacts on its portion of the Bulk Electric System

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	2023-07_Unofficial_Comment_Form Draft_4_110724_MRO.docx

Comment

Requirement R3 indicates forecasting Load, generation, and Transmission. There are significant barriers to modeling Load and generation based upon temperatures, notably forecasting out into the long-term planning timeframes. With that said, the MRO NSRF recommends that the NERC and drafting team develop implementation guidance and/or a reliability guideline to ensure Planning Coordinators can meet the requirements in the R3 section.

Several terms in the TPL-008-1 ERO Benchmark Weather Event Development and Maintenance Process DRAFT indicated defined terms are located in the glossary of terms, yet these terms are not defined in the glossary of terms. The term Zoneal is used rather than the term Zonal. There are also acronyms that do not represent the words spelled, for example it lists Affected Zonal Entity as ARE rather than the more representative term AZE.

Definitions Refer to the NERC Glossary of Terms3 for the below capitalized terms used in this process.

• Affected Zoneal Entity (ARE)

• Compliance Enforcement Authority (CEA)

• Coordinated Oversight

• Extreme Temperature Assessment (ETA)

• Lead Zoneal Entity (LRE)

• Multi-Zone Registered Entity (MRRE)

Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

1. Requirement R1 as drafted includes two separate requirements, i.e. to (1) identify responsibilities amongst applicable PCs and TPs, and (2) complete an Extreme Temperature Assessment every five years.

BC Hydro suggests that these are separate objectives and recommends that this Requirement be split to reflect these accordingly for enforceability (e.g. incident severity level), and cause-based incident monitoring.

2. BC Hydro’s understanding is that in order to determine the Contingencies that have a more severe impact per R7, the ETA needs to account for all contingencies within the identified zone(s), and not just those within its portion of the BES. Please confirm or provide additional clarity as appropriate.

3. Requirement R4 and the associated VSL Levels reference “the coordination process developed in Requirement R3”. R3 requires a benchmark planning cases development process, it does not require a coordination process.

BC Hydro recommends Recommend revising R4 and the associated VSL Levels for clarity and consistency.

BC Hydro also recommends that the language of R3 be revised to read “to implement a documented process” rather than “to implement a process”.

4. The VSL Table for Requirement R1 indicates a Severe Level if an entity “failed to identify individual and joint responsibilities”. There are no other Severity Levels associated with responsibilities identification, which is conducive to an interpretation that failing to identify even one of the R2 through R11 associated responsibility would be classified as a Severe VSL. BC Hydro suggests that failing to identify one or less than the full set of responsibility should carry less Severity Levels, and recommends that this be reflected in the lower Severity Levels as well.

5. The High and Severe VSL Levels for Requirement R8 are based on an entity’s failing to evaluate the results of the sensitivity (High VSL) and benchmarking cases (Severe VSL). R8 and its associated M8 do not explicitly require that an evaluation be also retained as evidence of compliance, in addition to the results documentation.

BC Hydro recommends that the R8, M8 and corresponding VSL Levels be revised for consistency.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

- ITC believes that the Yes for NCLL for P0 Sensitivity Cases should be changed to No. If it is deemed important to analyze a sensitivity case, the system should be able to serve firm load both for system normal and for single contingencies. With the requirements left as proposed, entities would need to proactively start shedding load for changes in generation, real and reactive forecasted Load, or transfers. System Operators will be forced to rely on preventative load shed during long term construction outages when experiencing extreme weather as it is highly likely that these will not be able to be cancelled.
- ITC believes that the Yes allowing for NCLL for P1 Base and Sensitivity Cases should be changed to No. ITC believes that a reliable system should be able to serve firm load for system normal and for single contingencies. Utilities typically schedule long term construction outages during winter (off-peak) and then experience extreme temperature scenarios. System Operators will need to rely on preventative load shed during these long term construction outages, that could not be cancelled if entities include NCLL as part of their corrective action plan.
- **ITC suggests that Footnote 6 (Page 12) include a clarification that Non Consequential Load Loss shall not be the only element in a Corrective Action Plan. See below:**
    - Benchmark planning cases require the development of a Corrective Action Plan when the responsible entity's portion of the BES is unable to meet the performance requirements for categories P0 or P1. Additionally, in benchmark planning cases, Non-Consequential Load Loss is not permitted for category P0 and **Non Consequential Load Loss shall not be the only element of a Corrective Action Plan unless approved by applicable regulatory authorities or governing bodies responsible for retail electric service issues.** *See Requirement R9 for the relevant requirements.*
- Specify if temperature is F or C on benchmark table of events. Clarify and specify timing on standard on when they will review the benchmark events.
- In DRAFT ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance Standards Development and Engineering Process Document October 2024, ITC suggests moving footnote 4 page 2 into the Process Overview and clarify if these actions will happen every cycle, or just the first iteration.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

No additional comments.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1, Group Name Exelon

Answer	

Document Name	
Comment	

Below are a few additional comments or questions for the drafting team to consider:

1. Clarify what “long-term transmission planning horizon” is in Requirement 3.1, which is the target time horizon for this standard. Currently NERC definition indicates year 6-10 or beyond. From our understanding, our PC intends to align with LTRTP.

2. Based on our interpretation, a benchmark temperature event doesn’t have to be a historical event. Is that correct?

Likes 0	
Dislikes 0	
Response	

Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson

Answer	
Document Name	
Comment	

RF appreciates the efforts of the Standards Drafting Team to apply comments recieved.

Likes 0	
Dislikes 0	
Response	

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

Answer	
Document Name	
Comment	

NPCC RSC agrees with the changes proposed by the standard drafting team.

Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 5	
Likes 0	
Dislikes 0	
Response	

Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	
Document Name	
Comment	
The IRC SRC is concerned that Requirement R3 unnecessarily and inadvertently limits the ability of entities to properly develop their benchmark planning cases. Specifically, the IRC SRC is concerned that R3 could be understood to mean that entities are limited to making the adjustments specifically described in R3 and are prevented from making adjustments necessary to ensure that the generation necessary to serve load is available so that the case can solve. As the drafting team recognizes in the Technical Rationale, adjusting the case to ensure that it contains enough generation to serve the modeled load is essential to ensure that the standard does not stray into the realm of resource adequacy issues and fully complies with paragraph 94 of FERC Order No. 896, which states that resource adequacy is not in scope for this project. While the IRC SRC appreciates this recognition, the Technical Rationale is not a binding document, and future revisions to the standard may introduce additional ambiguity regarding what types of adjustments are permissible under Requirement R3.	

To clarify the standard and better position it for future revisions, the IRC SRC recommends that the drafting team revise Part 3.2 by replacing the period at the end of Part 3.2 with the following: “, provided that the responsible entity may adjust the total modeled generation or Load in each case as necessary to allow the total modeled generation to serve the total modeled System Load.”

The IRC SRC also recommends that Requirement R4 be revised as needed to align with any revisions made to Requirement R3.

In addition, the IRC SRC requests that the ERO develop a Reliability Guideline for this proposed standard, and in particular, for Requirement R3 showing how a Planning Coordinator would adjust the benchmark planning case to ensure that it contains enough generation necessary to serve load.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

ERCOT joins the comments submitted by the IRC SRC for this question and adopts them as its own.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2

Answer	
Document Name	

Comment

The NYISO would like to confirm that is it acceptable to use additional (beyond those directed in Requirement 2) weather metrics to identify the benchmark temperature events. For example, summer extreme conditions could include a temperature-humidity index which integrates temperature and humidity and is shown to be a more robust predictor of peak loads than temperature alone. Likewise, winter extreme conditions could include a wind component (i.e., a wind-chill index). In either case, the associated temperature value could easily be extracted, as necessary, for any follow-on analysis (e.g., line ratings) requiring temperature specifically.

The NYISO would like to confirm that is it acceptable to use additional (beyond those directed in Requirement 2) averaging mechanisms which have been demonstrated to be robust predicators of extreme peak loads. For example, the NYISO currently employs a three-day weighted average temperature index for summer conditions and a three-day weighted average of a temperature-wind index variable for winter conditions.

The NYISO would like to confirm that is it acceptable to leverage their own knowledge and expertise in constructing the specific extreme heat and cold temperature events to be studied, within reasonable constraints, such as the 40-year historic period.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	
Document Name	

Comment

Another concern for SPP is applicable to the model not being able to solve which includes the sensitivity (stability cases for P0 condition). It is unclear on the expectation of the drafting team in reference to the PC not being able to solve the models for the various categories of the ETA. Also, there are concerns around gathering and aligning the appropriate temperature data independently.

Requirement R3 indicates forecasting Load, generation, and Transmission. There are significant barriers to modeling Load and generation based upon temperatures, notably forecasting out into the long-term planning timeframes. With that said, SPP recommends that the NERC and drafting team develop implementation guidance and/or a reliability guideline to ensure Planning Coordinators are able to meet the requirements in the R3 section.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

The DT should highly consider or leave it to Planning Coordinator's discretion when it comes to sensitivities: PC's should be given the opportunity/flexibility in determining whether sensitivities are needed or as to how much study is needed regarding sensitivities.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	
Document Name	

Comment

OPG supports NPCC Regional Standards Committee's comments.

Likes 0	
Dislikes 0	

Response

Amy Wilke - American Transmission Company, LLC - 1

Answer	
Document Name	

Comment

While ATC has voted in support of approving project 2023-07; we are also in support of the comments provided by the MRO NSRF.

Likes 0	
Dislikes 0	

Response