Comment Report

Project Name:	Project 2015-09 Establish and Communicate System Operating Limits
Comment Period Start Date:	6/19/2020
Comment Period End Date:	8/26/2020
Associated Ballots:	2015-09 Establish and Communicate System Operating Limits CIP-014-3 AB 2 ST 2015-09 Establish and Communicate System Operating Limits FAC-003-5 AB 2 ST 2015-09 Establish and Communicate System Operating Limits FAC-011-4 AB 3 ST 2015-09 Establish and Communicate System Operating Limits FAC-013-3 AB 2 ST 2015-09 Establish and Communicate System Operating Limits FAC-014-3 AB 3 ST 2015-09 Establish and Communicate System Operating Limits Implementation Plan AB 3 OT 2015-09 Establish and Communicate System Operating Limits IRO-008-3 IN 1 ST 2015-09 Establish and Communicate System Operating Limits PRC-002-3 AB 2 ST 2015-09 Establish and Communicate System Operating Limits PRC-023-5 AB 2 ST 2015-09 Establish and Communicate System Operating Limits PRC-026-2 AB 2 ST 2015-09 Establish and Communicate System Operating Limits TOP-001-6 IN 1 ST

There were 76 sets of responses, including comments from approximately 173 different people from approximately 119 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Industry response to the SDT's second posting, and specifically the new FAC-011-4, Requirement 6, indicated numerous and significant concerns. Among the concerns were many industry commenters stating that SOL exceedances should be determined using the TOP and IRO standards and not an FAC standard. The SDT has responded by revising FAC-011-4, Requirement 6, removing FAC-014-3, Requirement 6, and adding TOP-001-6, Requirement R25 and IRO-008-3, Requirement R7 to have SOL exceedances determined by TOPs and RCs, respectively, per the RC's SOL methodology and the performance framework now within FAC-011-4, Requirement R6. Do you agree with revisions made by the SDT in FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations?

2. Industry response to the SDT's second posting included many concerns regarding increased compliance and administrative logging from the SOL exceedance construct in FAC-011-4, Requirement 6. In response to these concerns, the SDT revised Requirement 6, added a new Requirement 7 to document a risk-based approach for determining how SOL exceedances are identified, and how they are communicated, including timeframes. The SDT also revised requirements and measures in TOP-001 (M14, R15, M15) and IRO-008 (R5, M5, R6, M6) to address this concern. Do you agree with revisions made by the SDT in FAC-011-4, TOP-001-6 and IRO-008-3 with regard to increased compliance risk and administrative logging?

3. If you have any other comments regarding FAC-011-4 that you haven't already provided, please provide them here.

4. The SDT has received numerous comments on the new FAC-015-1 since the first posting. Acknowledging these comments, the SDT has withdrawn FAC-015-1 and consolidated its four requirements into three requirements (R6 – R8) in proposed FAC-014-3 that retain the minimum requirements the SDT believes will allow retirement of FAC-010 and maintain limit/criteria coordination between operations and planning. Do you agree with the proposed requirements R6 through R8 in FAC-014-3?

5. If you have any other comments regarding FAC-014-3 that you haven't already provided, please provide them here.

6. If you have any other comments regarding TOP-001-6 or IRO-008-3 that you haven't already provided, please provide them here.

7. With the retirement of FAC-010, and the elimination of Planning-based SOLs and IROLs, do you agree with the changes to CIP-014, FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026?

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	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Andy Crooks	SaskPower Corporation	1	MRO
					Bryan Sherrow	Kansas City Board of Public Utilities	1	MRO
					Bobbi Welch	Omaha Public Power District	1,3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Bobbi Welch	Midcontinent ISO	2	MRO
					Douglas Webb	Kansas City Power & Light	1,3,5,6	MRO
					Fred Meyer	Algonquin Power Co.	1	MRO
					John Chang	Manitoba Hydro	1,3,6	MRO
					James Williams	Southwest Power Pool, Inc.	2	MRO
					Jamie Monette	Minnesota Power / ALLETE	1	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO

					Sing Tay	Oklahoma Gas & Electric	1,3,5,6	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Troy Brumfield	American Transmission Company	1	MRO
PPL - Louisville Gas and Electric Co.	Devin Shines	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
Douglas Webb	Douglas Webb		MRO,SPP RE	Westar-KCPL	Doug Webb	Westar	1,3,5,6	MRO
					Doug Webb	KCP&L	1,3,5,6	MRO
New York Independent System Operator	Gregory Campoli	2		ISO/RTO Standards Review Committee	Gregory Campoli	NYISO	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Mark Holman	PJM Interconnection, L.L.C.	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Ali Miremadi	CAISO	2	WECC
					Kahtleen Goodman	ISO-NE	2	NPCC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO

					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					David Hartman	Arizona Electric Power Cooperative, Inc.	1	WECC
Lincoln Electric System	Kayleigh Wilkerson	5		Lincoln Electric System	Kayleigh Wilkerson	Lincoln Electric System	5	MRO
					Eric Ruskamp	Lincoln Electric System	6	MRO
					Jason Fortik	Lincoln Electric System	3	MRO
					Danny Pudenz	Lincoln Electric System	1	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Carey	FirstEnergy - FirstEnergy Solutions	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC

					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Eversource Energy	Quintin Lee	1		Eversource Group	Sharon Flannery	Eversource Energy	3	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Helen Lainis	IESO	2	NPCC
					David Kiguel	Independent	7	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC
					Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC

					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Nurul Abser	NB Power Corporation	1	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC
					Silvia Parada Mitchell	NextEra Energy, LLC	4	NPCC
					Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					John Hasting	National Grid USA	1	NPCC
					Michael Jones	National Grid USA	1	NPCC
					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable

					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Jonathan Hayes	Southwest Power Pool Inc	2	MRO
					Tim Miller	Southwest Power Pool Inc.	2	MRO
					Yasser Bahbaz	Southwest Power Pool Inc.	2	MRO
					will Tootle	Southwest Power Pool Inc.	2	MRO
					Charles Cates	Southwest Power Pool Inc.	2	MRO
OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay	6	SPP RE	OKGE	Sing Tay	OGE Energy - Oklahoma	6	MRO
					Terri Pyle	OGE Energy - Oklahoma Gas and Electric Co.	1	MRO
					Donald Hargrove	OGE Energy - Oklahoma Gas and Electric Co.	3	MRO
					Patrick Wells	OGE Energy - Oklahoma Gas and Electric Co.	5	MRO

1. Industry response to the SDT's second posting, and specifically the new FAC-011-4, Requirement 6, indicated numerous and significant concerns. Among the concerns were many industry commenters stating that SOL exceedances should be determined using the TOP and IRO standards and not an FAC standard. The SDT has responded by revising FAC-011-4, Requirement 6, removing FAC-014-3, Requirement 6, and adding TOP-001-6, Requirement R25 and IRO-008-3, Requirement R7 to have SOL exceedances determined by TOPs and RCs, respectively, per the RC's SOL methodology and the performance framework now within FAC-011-4, Requirement R6. Do you agree with revisions made by the SDT in FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations?

John Allen - City Utilities of Springfield, Missouri - 4

Answer	No
Document Name	

Comment

I agree SOL exceedances should be determined using the TOP and IRO standards and not an FAC standard. However, the standards need to be results-based and define *a clear and measurable expected outcome* for all Registered Entities. Otherwise it becomes more of a guideline that is difficult to enforce. It appears each Reliability Coordinator has some flexibility to develop it's own method for identifying SOL exceedances in its SOL methodology. If so, then what is going to prevent two adjacent Reliability Coordinators from arriving at different conclusions and having disagreements during Real-time operations? What is going to prevent two adjacent Transmission Operators in different Reliability Coordinator Areas from having disagreements? What is going to prevent disagreements between Registered Entities and their Regional Entity? How are those disagreements resolved? The purpose of the SOL Whitepaper was to establish a common understanding of SOL exceedances across North America. Hopefully these requirements are not detrimental to that effort and the purpose of this project.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 3,4,5,6

Answer	No
Document Name	

Comment

NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.

Likes 0	
Dislikes 0	

Response

Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System

Answer	No

Document Name	
Comment	

In consideration of past confusion related to whether an SOL exceedance is a regulatory violation, LES suggests the following changes to better clarify R6:

R6.2.1 Steady State post-Contingency flow through Facilities within applicable Emergency Ratings. *[Remove: Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating.]*

R6.2.3 Predetermined stability limits are not exceeded. *[Remove: The stability performance criteria defined in the Reliability Coordinator's SOL methodology are met.]*

Likes 0	
Dislikes 0	
Response	

Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8

Answer	No
Document Name	
Comment	

R6.1: The way this is worded is awkward and confusing. Why are you using the language "no contingencies" instead of "pre-contingency state"?

Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	2015-09_Unofficial_Comment_Form_202006 - SOCO Comments Final.pdf
Comment	

Detailed comments are in the attached file with special formatting for clarity and emphasis where needed (strike-through, highlighting, etc.).

Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	
Response	

Truong Le - Truong Le On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 5, 3; Chris Gowder, Florida Municipal Power Agency, 6, 4, 5, 3; Dale Ray, Florida Municipal Power Agency, 6, 4, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 5, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Truong Le	
Answer	No
Document Name	
Comment	
FMPA supports John Allen's, City Utilities of Springfield, Missouri, comments.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA suggests the proposed TOP-001-6 requirement R25 be removed. BPA believes the requirement that the TOP use the RC SOL methodology for establishing SOLs in the Operations horizon is already covered in FAC-014 R2. The proposed FAC-011-4 R6 will require the RC SOL Methodology to explicitly include applicability to “Real-time monitoring, Real-time Assessments, and Operational Planning Analysis”. (Using the RC West SOL Methodology as an example, the applicability of the methodology to these sub-horizons is already explicit in the document.) BPA believes the proposed TOP-001-6 R25 is redundant and simply adds to the burden of compliance documentation. BPA has no concerns with the proposed revisions to IRO-008-3 R5/R6.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE appreciates the standard drafting team’s (SDT) efforts to clarify System Operating Limit (SOL) exceedance use and determination. As Texas RE understands it, proposed FAC-011-4 Requirement R6 establishes the required system performance framework in an RC’s SOL methodology for determining SOL exceedances in the RC’s Real-time monitoring, Real-time Assessment (RTA) and Operation Planning Analyses (OPA)	

activities. Texas RE remains concerned, however, that proposed FAC-011-4 could be read to permit the broader use of less conservative Facility Ratings in identifying and responding to SOL exceedances by permitting entities to operate the system without identifying an SOL and implementing an Operating Plan when: (1) pre-contingency steady state flows are within Emergency Ratings in circumstances in which System adjustments to return the flow to within a Facility's Normal Rating could be executed and completed within the applicable time duration of the Emergency Ratings; and (2) post-contingency flows through Facilities are within the Facility's highest Emergency Rating.

Regarding post-contingency flows in particular, Texas RE is concerned that entities would not be required to identify post-contingency flows and voltages above a Facility's two-hour Emergency Rating as an SOL. Texas RE notes that the "highest Emergency Rating" is usually an extreme limit associated with a very short duration to mitigate an exceedance of the Emergency Rating. For example, ERCOT ISO utilizes a 15-minute rating (along with 2-hour and continuous) that is defined as shown below:

"The 15-minute MVA rating of a Transmission Element, including substation terminal equipment in series with a conductor or transformer, at the applicable ambient temperature and with a step increase from a prior loading up to 90% of the Normal Rating. The Transmission Element can operate at this rating for 15 minutes, assuming its pre-contingency loading up to 90% of the Normal Rating limit at the applicable ambient temperature, without violation of NESC clearances or equipment failure. This rating takes advantage of the time delay associated with heating of a conductor or transformer following a sudden increase in current."

As Texas RE reads the proposed FAC-011-4, R 6.2.1 language, SOL methodologies could be designed to permit post-contingency flows above a Facility's two-hour Emergency Rating but below the highest 15-minute rating. By possibly not requiring entities to identify this instance as an SOL exceedance in its OPA or RTA, an entity would correspondingly not be required to create an Operating Plan to mitigate the exceedance and would not be required to take pre-emptive steps to address such post-contingency flows identified in Real-time. In turn, if an Operating Plan is not created, the entity potentially would not know the adjustments needed to address the exceedance and the duration in which these adjustments can be completed.

Texas RE observes that the proposed NERC System Operating Limit Definition and Exceedance Clarification provides: "Normal voltage limits are typically applicable for the pre-Contingency state while emergency voltage limits are normally applicable for the post-Contingency state. SOL exceedance with respect to these voltage limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event."

Texas RE supports this approach, but believes additional clarity is necessary in the Standard Requirement language itself to require entities more proactive action to address post-contingency identified Emergency Rating exceedances rather than only requiring entities to develop Operating Plans when exceedances of the highest Emergency Rating are identified.

Additionally, Texas RE recommends the SDT consider the following:

- In Part 6.1, rephrase "System performance for no Contingencies demonstrates the following to "System performance **where there are no applied** Contingencies demonstrates the following". Alternatively, "applied" could be moved to be after "Contingencies".
- In Part 6.1.2, there is typically no time duration associated with voltage limits, nor is there a reference to time duration in the proposed definition of System Voltage Limits. Based on this language it should or a SOL exceedance for a System Voltage Limit may not occur based on this language. The reliability of the grid could suffer by never returning to "normal" System Voltage Limits because no time duration is specified.

- In Part 6.2.1 “Steady State” is capitalized (and also capitalized in the rationale document in several places), but there is no current or proposed definition in the NERC Glossary. Texas RE has experienced entities asking about a definition during recent engagements.
- Additionally, within Part 6.2, there may need to be a reference regarding “Predetermined stability limits are not exceeded”. It would appear that the omission would allow a “predetermined stability limit” to be exceeded for a single contingency and thus meet system performance, which seems to contradict an N-1 approach to reliable operations.
- Part 6.1.2 states “System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.” The proposed definition of System Voltage Limit does not define a time period. So there nothing to describe what the “specified time duration of those emergency System Voltage Limits” is. Texas RE recommends the System Voltage definition include a time duration to be more effective, reliable, and applicable.

Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC believes that the revisions made by the SDT will improve the reliability with regard to SOL exceedance. However, it does not provide consistent framework for defining SOL exceedances for all registered entities. Therefore, two adjacent Reliability Coordinators can reach different conclusions to address a common event during real-time operations.	
Likes 0	
Dislikes 0	
Response	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC supports the comments as submitted by EEI.	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 1, 5, 3, 6; Bryan Taggart, Westar Energy, 1, 5, 3, 6; Derek Brown, Westar Energy, 1, 5, 3, 6; Grant Wilkerson, Westar Energy, 1, 5, 3, 6; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., ; James McBee, Westar Energy, 1, 5, 3, 6; Marcus Moor, Westar Energy, 1, 5, 3, 6; - Douglas Webb, Group Name Westar-KCPL	
Answer	No
Document Name	
Comment	
The Evergy companies support, and incorporate by reference, Edison Electric Institute's response to Question No. 1.	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy supports the comments provided by EEI: *While the latest modifications are an improvement over the previously proposed modifications, EEI does not support certain changes made to FAC-011-04, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations. Specifically, the proposed FAC-011-4 modifications contain requirements related to the establishment of limits, contingency events, and performance framework that eliminate a necessary level of flexibility and clarity that currently exists in the FAC-011-3 Reliability Standard. Requirement 6, subpart 6.1/6.1.3 of FAC-011-4 affords entities little flexibility when determining stability performance for system conditions with no contingencies by requiring "predetermined stability limits" to not be exceeded. (R6.1) This seems to be in contrast with the flexibility afforded for single contingency conditions, which require the "stable performance criteria defined in the Reliability Coordinator's SOL methodology" to be met, based on predetermined stability limits or adjusted with real-time or offline analysis techniques. (R6.2). EEI suggest that R6.1.3 be removed or revised to more closely aligned with R6.2.* *Additionally, the implementation plan proposed by the SDT should be extended to account for the extensive work that may be required by responsible entities to document and track what is expected to be a significantly larger numbers of documented exceedances under the proposed new FAC-011-04 and associated TOP-001-6 Reliability Standards. Many entities may need to make certain enhancements to systems such as their energy management systems (EMS) and/or Real-time Contingency Analysis (RTCA) tools to accurately track and validate exceedances. New servers and other associated hardware, as well as software modifications may be necessary to meet these new logging requirements to track exceedances of very short duration and to record mitigation responses for every SOL exceedance regardless of the duration. This situation is further complicated for those entities using dynamic line ratings (e.g., ambient temperature ratings or wind speed adjusted ratings). To address this issue, the industry will need time to make these adjustments. Consequently, the 12 month implementation timeframe should be extended to a minimum of 24 months.*	
Likes 0	
Dislikes 0	

Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
On behalf of Exelon, Segments 1, 3, 5, & 6 Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
While the latest modifications are an improvement over the previously proposed modifications, EEI does not support certain changes made to FAC-011-04, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations. Specifically, the proposed FAC-011-4 modifications contain requirements related to the establishment of limits, contingency events, and performance framework that eliminate a necessary level of flexibility and clarity that currently exists in the FAC-011-3 Reliability Standard. Requirement 6, subpart 6.1/6.1.3 of FAC-011-4 affords entities little flexibility when determining stability performance for system conditions with no contingencies by requiring “predetermined stability limits” to not be exceeded. (R6.1) This seems to be in contrast with the flexibility afforded for single contingency conditions, which require the “stable performance criteria defined in the Reliability Coordinator’s SOL methodology” to be met, based on predetermined stability limits or adjusted with real-time or offline analysis techniques. (R6.2). EEI suggest that R6.1.3 be removed or revised to more closely aligned with R6.2. Additionally, the implementation plan proposed by the SDT should be extended to account for the extensive work that may be required by responsible entities to document and track what is expected to be a significantly larger numbers of documented exceedances under the proposed new FAC-011-04 and associated TOP-001-6 Reliability Standards. Many entities may need to make certain enhancements to systems such as their energy management systems (EMS) and/or Real-time Contingency Analysis (RTCA) tools to accurately track and validate exceedances. New servers and other associated hardware, as well as software modifications may be necessary to meet these new logging requirements to track exceedances of very short duration and to record mitigation responses for every SOL exceedance regardless of the duration. This situation is further complicated for those entities using dynamic line ratings (e.g., ambient temperature ratings or wind speed adjusted ratings). To address this issue, the industry will need time to make these adjustments. Consequently, the 12 month implementation timeframe should be extended to a minimum of 24 months.	
Likes 0	
Dislikes 0	
Response	

Lee Maurer - Oncor Electric Delivery - 1	
Answer	No
Document Name	
Comment	
Oncor supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
ACES believes that the revisions made by the SDT will improve the reliability with regard to SOL exceedance. However, it does not provide consistent framework for defining SOL exceedances for all registered entities. Therefore, two adjacent Reliability Coordinators can reach different conclusions to address a common event during real-time operations.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
Please see comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	

WAPA partially agrees with the SDT revisions that address how SOL exceedances are determined and used in FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3. The flexibility afforded to each Reliability Coordinator to determine its own framework based upon its SOL methodology is an absolute must, but the concept of "a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments" is problematic and vague. It is noted that the concept of a "risk-based approach" does not carry over into the actual selection of single or multiple Contingency events which is a core tenet of the existing FAC-011-3. Incorporating aspects of risk are essential to the establishment of SOL exceedances (e.g., defining credible multiple contingencies) and should be addressed in each Reliability Coordinators SOL methodology, but this perpetuates the confusion that has plagued the existing FAC-011-4 and elsewhere.

Likes 0	
Dislikes 0	
Response	

Marco Rios - Pacific Gas and Electric Company - 1	
Answer	No
Document Name	
Comment	

FAC-011-4 contains quite a number of required changes to the RC's SOL Methodology to try to align it more for use with Planning Horizon studies. The changes generally seem appropriate, but questions remain about the details of implementation – have all differences between Planning and Operations been adequately considered? A detailed parsing of each RC's existing SOL Methodology versus a draft modified according to this standard may be needed to fully grasp the potential for issues related to these changes.

PG&E has no concerns with the applicable use of TOP-001-6 for SOL exceedance and determinations.

Likes 0	
Dislikes 0	
Response	

Jack Stamper - Clark Public Utilities - 3	
Answer	No
Document Name	
Comment	

While FAC-011-4 requires the RC to Provide Planning Coordinators and Transmission Planners with the RC Methodology, FAC-014-3 does not allow the Planning Coordinators and Transmission Planners to respond to the RC established SOLs and requirese the Planning Coordinators and Transmission Planners to establish their own SOLs that are equally limiting or more limiting than the RC established SOLs.

What if there is a technical problem with the RC established SOLs. There is not listed recourse in FAC-014-3 for the PC or the TP to provide comments on technical problems with the RC established SOLs and a requirement that the RC address those problems.

Clark Public Utilities is a small utility and as a TP, it doubts that the RC West is going to be very concerned about Clark's small area of 115 kV transmission. RC West has already informed Clark by email that it will only be in direct contact with its BA and TOP members and Clark need to go through its TOP (Bonneville Power Administration) to deliver its annual Transmission Planning Assessment. FAC-011 and FAC-014 need to address the changed relationship between non-BA and non-TOP entities in the West that are part of the RC West Reliability Coordinator footprint.

RC West's relationship with non-BAs and non-TOPs is different that the Peak RC relationship, RC West seems only to want to deal directly with the larger organizations. While this may only be a situation in the West, NERC should look closer at what the RC to other entity relations should be so the overall compliance can be more efficient and so that smaller entities are not creating work that is not going to be used. That is just paper pushing to make sure a compliance box is checked off and is not doing anything to assure reliability.

Clark believes that the relationship heirarchy for the Operating Horizon should be from the RC to the Planning Coordinator to the Transmission Planner. The Planning Coordinator should develop its SOL Methodology using the RC Methodology and RC Contingincies for the Operating Horizon and its own methodology and its own contingencies for the Planning Horizon. The PC should distribute its methodology and contingency list to Transmission Planners in its footprint. TPs then should have the ability to coordinate their own contingincies with the PC provided contingincy list. Once that is done (i.e. the TP and PC agree on the contingencies to be used in studies) the TP should then establish its SOLs for the Operating Horizon and Planning Horizion and provide those to its PC for comments and revision or approval. The PC should provide its consoldated SOLs for the Operating Horizon and Planning Horizion to the RC for comments and revision or approval. Then the RC should provide the final approved list of SOLs for all PCs and TPs in its footprint to all TOPs in its footprint.

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	Yes
Document Name	

Comment

FAC-014-3 No

The FAC-014-3 R6 language opens the door for the Reliability Coordinator (RC) to dictate to the Transmission Planner (TP), through the RC's SOL methodology, the following items used in planning assessments: facility ratings, voltage criteria, and stability criteria. Establishment of facility ratings are the responsibility of the TO under FAC-008, while establishment of voltage and stability criteria are the responsibility of the TP under TPL-001-4. These responsibilities should not be ceded to another party. Long term implications are that the RC, through control of such items as facility ratings, voltage and stability limits, could force a TO to enter into corrective action plans and associated capital expenditures that they otherwise would not.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments".

The MRO-NSRF agrees with revisions made by the SDT in FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations. The MRO-NSRF supports the proposed revisions to FAC-011-4, Requirement 6, which while providing a consistent framework for defining a SOL Exceedance within the RC methodology, also provides some flexibility to each RC in the application of the framework within its footprint.

However, the MRO NSRF does recommend a change to FAC-011-4 R6.4 language. Specifically, the proposed language reads, "planned manual load shedding is acceptable only after all available System adjustments have been made." Although the MRO NSRF understands the intent of this language (i.e. load shed is a last resort solution), we don't believe it is the SDT's intention to require every System adjustment to actually be implemented in a study or model prior to determining that manual load shed is the best planned response. We believe the intent is to ensure all available adjustments have been appropriately assessed before deciding on the solution of last resort. We recommend changing the language to, "planned manual load shedding is acceptable only after all available System adjustments have been assessed."

The MRO NSRF notes there remains the potential for differences between adjacent Reliability Coordinators over the methods used to identify SOL exceedances.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

Duke Energy agrees with the revisions but due to the numerous methodologies, procedures, processes, tools, and training impacts associated with this Project, suggest extending implemenation period from 12 months to 30 months.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	Yes
Document Name	
Comment	

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	Yes
Document Name	
Comment	

MEC supports the MRO NSRF comments.

The MRO-NSRF agrees with revisions made by the SDT in FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations. The MRO-NSRF supports the proposed revisions to FAC-011-4, Requirement 6, which while providing a consistent framework for defining a SOL Exceedance within the RC methodology, also provides some flexibility to each RC in the application of the framework within its footprint.

However, the MRO NSRF does recommend a change to FAC-011-4 R6.4 language. Specifically, the proposed language reads, "planned manual load shedding is acceptable only after all available System adjustments have been made." Although the MRO NSRF understands the intent of this language (i.e. load shed is a last resort solution), we don't believe it is the SDT's intention to require every System adjustment to actually be implemented in a study or model prior to determining that manual load shed is the best planned response. We believe the intent is to ensure all available adjustments have been appropriately assessed before deciding on the solution of last resort. We recommend changing the language to, "planned manual load shedding is acceptable only after all available System adjustments have been assessed."

The MRO NSRF notes there remains the potential for differences between adjacent Reliability Coordinators over the methods used to identify SOL exceedances.

Likes 0	
Dislikes 0	
Response	

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	Yes
Document Name	
Comment	

MEC Supports NSRF Comments

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

Please see our comments in Q#2 and Q#4

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Dominion Energy supports comments submitted by EEI. Dominion agrees that the implmentation period should be extended to allow entities the appropriate time to make changes to complex systems and processes.

Likes 0	
Dislikes 0	

Response

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE

Answer	Yes
Document Name	

Comment

OGE agrees with MRO-NSRF's comments on replacing IROL definition language with "Adverse Reliability Impact" as shown below:

Proposed Language:

FAC-011-4, Parts 6.1.4 and 6.2.4. Adverse Reliability Impacts do not occur. 1

Footnote 1, page 5: Stability evaluations and assessments of Adverse Reliability Impacts can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

FAC-011-4, Part 6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that Adverse Reliability Impacts do not occur.

FAC-011-4, Part 7.1.3. Post-contingency SOL exceedances that are identified to have a validated risk of Adverse Reliability Impacts

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	Yes
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum.

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	Yes
Document Name	

Comment

ATC appreciates the changes made by the SDT to address industry concerns and we are supportive of the current revisions to these standards. We do recommend one change to FAC-011-4 R6.4 language. Specifically, the proposed language reads, "planned manual load shedding is acceptable only after all available System adjustments have been made." Although we understand the intent of this language (i.e. load shed is a last resort solution), we don't believe it is the SDT's intention to require every System adjustment to actually be implemented in a study or model prior to determining that manual load shed is the best planned response. We believe the intent is to ensure all available adjustments have been appropriately assessed before deciding on the solution of last resort. We recommend changing the language to, "planned manual load shedding is acceptable only after all available System adjustments have been assessed."

Likes 0	

Dislikes 0	

Response

Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter

Answer	Yes
Document Name	

Comment

FAC-014-3 The statement "any instability identified in its Planning Assessment of the Near-Term Transmission…" seems unclear. I think an improvement and more clear statement might be, "any stability criteria violation identified in its Planning Assessment of the Near-Term Transmission…".

The revision that Oncor is proposing also seems to better align with the deliverables outlined in R7.1 – R7.5, and in particular, R7.3: The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria).

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer	Yes
Document Name	

Comment

We agree with the revisions but offer the following for consideration and improvement.

a. Requirement R7 – plural word "communications" needs to be changed to be singular.

b. The proposed modification to IRO-008 requirement R6 effectively requires the RC to notify TOPs and BAs when SOL exceedances have been mitigated or prevented in accordance with its SOL Methodology; however, there is no specific requirement in proposed FAC-011-4 that requires the SOL methodology to address notification of SOL exceedance mitigation or prevention. It only specifically requires the SOL methodology to addresses notification of SOL exceedances. While it is true that proposed FAC-011-4 requirement R7 can be interpreted to include not only notification of SOL exceedances, but also notification of SOL exceedance mitigation or prevention, it might be clearer to enhance FAC-011-4 requirement R7 by specifically addressing notification of SOL exceedance mitigation and prevention. If this modification is not made, RCs might not know that their SOL methodology is supposed to address notification of SOL exceedance mitigation and prevention if they don't happen to read proposed IRO-008 requirement R6. Potential language enhancement could be "Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances (and associated exceedance mitigation) identified as part of Real-time monitoring and Real-time Assessments must be communicated…"

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 Regional Standards Committee	
Answer	Yes
Document Name	

Comment
Please consider a 24 calendar month implementation plan, instead of 12 calendar months. Additional tracking, validation, and documentation of exceedances will be necessary. Enhancements to existing tracking tools may be required.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	

Comment
We believe the future for SOL communication will require automation for exceedances to be logged and reported, as based on RC and TOP methodology. We have concerns with an increase in data logging requirements and ask the SDT to look at TOP-001 and we question whether it is the best place for specifications for determining real-time assessments? Perhaps it is better in TOP-002? Also we believe an SOL needs to be clearly defined and not open to interpretation from region to region. In addition, we believe that a 12 month implementation plan wouldn't allow enough time to incorporate these new changes, to procure hardware and software, and therefore we ask that a 30 month implementation plan be implemented.

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	

Comment

Please consider a 24 calendar month implementation plan, instead of 12 calendar months. Additional tracking, validation, and documentation of exceedances will be necessary. Enhancements to existing tracking tools may be required.

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 direction of the changes made to FAC-011-04, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations. However, the implementation plan should be extended to account for the additional work by responsible entities to document and track what is expected to be a significantly larger number of documented exceedances under the proposed new FAC-011-04 and associated TOP-001-6 Reliability Standards. Companies will need to make certain enhancements to systems such as their energy management systems (EMS) and/or Real-time Contingency Analysis (RTCA) tools to track accurately exceedances and validate exceedances. Consequently, the 12 month implementation timeframe would be insufficient to implement the new requirements and therefore request that the SDT extend the implementation plan to at least 24 months.

ITC believes however that in a similar way that industry responded to FAC-015, the same concerns exist for FAC-014-3 R7. Transmission Planners refer to TPL-001-4 (-5). It seems misplaced to have a requirement concerning the Near Term Assessment and its results in a FAC-014 standard.

Likes 0	
Dislikes 0	

Response

Colleen Campbell - AES - Indianapolis Power and Light Co. - 3

Answer	Yes
Document Name	

Comment

IPL offers no further comments.

Likes 0	
Dislikes 0	

Response	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Oncor supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
The ISO/RTO Council Standards Review Committee (IRC SRC) supports the changes made by the SDT to FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determination. That said, the IRC SRC offers the following comment for SDT consideration. While the IRC SRC agrees with the SDT that planned manual load shedding is a last resort, we believe a slight modification to the wording of **FAC-011-4, Part 6.4** is warranted to reflect that planned manual load shedding should only be implemented after all available System adjustments have been assessed and determined that no other available System adjustments can be accomplished in the time available to return the flow within limits without the risk of unplanned load shedding. Proposed revision to **FAC-011-4, Part 6.4**: "planned manual load shedding is acceptable only after all available System adjustments have been ***assessed*** (delete made)." Note: SPP was not party to the comment for Question #1.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	

Answer	Yes
Document Name	
Comment	

MISO supports the comments filed by the IRC SRC.

The ISO/RTO Council Standards Review Committee (IRC SRC) supports the changes made by the SDT to FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determination.

That said, the IRC SRC offers the following comment for SDT consideration. While the IRC SRC agrees with the SDT that planned manual load shedding is a last resort, we believe a slight modification to the wording of **FAC-011-4, Part 6.4** is warranted to reflect that planned manual load shedding should only be implemented after all available System adjustments have been assessed and determined that no other available System adjustments can be accomplished in the time available to return the flow within limits without the risk of unplanned load shedding.

Proposed revision to **FAC-011-4, Part 6.4**: “planned manual load shedding is acceptable only after all available System adjustments have been assessed.”

Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	
Comment	

None.

Likes 0	
Dislikes 0	

Response

Jamie Johnson - California ISO - 2

Answer	Yes
Document Name	
Comment	

California ISO agrees with comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	Yes
Document Name	
Comment	
Support the MRO-NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey	
Answer	Yes
Document Name	
Comment	
FAC-011-4 contains quite a number of required changes to the RC's SOL Methodology to try to align it more for use with Planning Horizon studies. The changes generally seem appropriate, but questions remain about the details of implementation – have all differences between Planning and Operations been adequately considered? A detailed parsing of each RC's existing SOL Methodology versus a draft modified according to this standard may be needed to fully grasp the potential for issues related to these changes. PG&E has no concerns with the applicable use of TOP-001-6 for SOL exceedance and determinations.	
Likes 0	
Dislikes 0	
Response	
Maurice Paulk - Cleco Corporation - 1,3,5,6	
Answer	Yes
Document Name	

Comment	
See SEE, EEI and MISO comments.	
Likes 0	
Dislikes 0	
Response	

Michael Courchesne - Michael Courchesne On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Michael Courchesne	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

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

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Hirchak - Cleco Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Glen Allegranza, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Ray Jasicki - Xcel Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Industry response to the SDT's second posting included many concerns regarding increased compliance and administrative logging from the SOL exceedance construct in FAC-011-4, Requirement 6. In response to these concerns, the SDT revised Requirement 6, added a new Requirement 7 to document a risk-based approach for determining how SOL exceedances are identified, and how they are communicated, including timeframes. The SDT also revised requirements and measures in TOP-001 (M14, R15, M15) and IRO-008 (R5, M5, R6, M6) to address this concern. Do you agree with revisions made by the SDT in FAC-011-4, TOP-001-6 and IRO-008-3 with regard to increased compliance risk and administrative logging?

Jack Stamper - Clark Public Utilities - 3

Answer	No
Document Name	

Comment

No. FAC-014 is administratively burdonsome on small entites by requiring it to accept RC established SOLs without any recourse to address technical problems with the RC established SOLs. It the RC is going to establish and communicate SOLS to a PC or a TP, there should be the ability for the PC or the TP to provide comments and a requirement for the RC to address those comments.

A better approach is discribed in Clark's answer to Question 1. Pay more attention to the changes that are occuring in the west (and maybe elsewhere). The RC is more eficient when dealing with larger entities (BAs, TOPs, and PCs). PCs should be the driving entity for work performed by TPs in the PC footprint. PCs establish the SOL Methodology (using the RC methodology for the Operings Horizon) used by its TPs,and would then consolidate its planning study results with the approved TP planning study results. The PC would then provide the consolidated results to the RC who would in turn provide the approved final SOL list to its TOPs'

Likes 0	
Dislikes 0	

Response

Marco Rios - Pacific Gas and Electric Company - 1

Answer	No
Document Name	

Comment

Generally, PG&E has no objections to the revisions, but has some concerns with implementation for FAC-011-4.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	No

Document Name	
Comment	
WAPA partially agrees with the SDT revisions that address how SOL exceedances are identified and communicated, but we do not agree with how the definitions of SOL versus SOL exceedances have been confused in FAC-011-4, specifically in Requirement R6 to include a performance framework in the Reliability Coordinator SOL methodology to determine SOLs exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses. We request that the SDT reconsider that the constraints that define how SOLs are established are categorically different than how exceedances are defined, identified in the Operations Horizon, and communicated.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
Please see comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT is concerned that the meaning of "communicated" in Requirement R7 is not sufficiently clear. ERCOT suggests that Requirement R7 be revised in order to clarify that communications may be electronic. Similar to the measures accompanying IRO-008, Requirement R5, and TOP-001, Requirement R15, Requirement R7 should be revised to expressly permit electronic communications. Moreover, ERCOT believes "electronic" communications should be defined to include the mere electronic posting of data that enables entities to access/view SOL exceedances. ERCOT further notes that it intends to vote in favor of FAC-011-4, provided Requirement R7 is clarified to provide that communications may be electronic.	
Likes 0	

Dislikes 0	

Response

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

Comment

FAC-011-4 R7

FAC-011-4 R7 implies the use of a “risk-based” approach for the communication aspects of R7.1.1 through R7.2.2.

“Risk-based” approach terminology is rare outside of FAC vegetation. As written, this terminology could result in compliance misinterpretation or misunderstanding by operations staff.

FAC Standards address the methodology of determining SOLs, COM Standards address the communication protocol between operations, and IRO Standards address interconnected operations of the Bulk Electric System (BES) including coordination with external entities.

The SPP Standards Review Group asks the SDT’s consideration that R7 should not be a Requirement in the FAC Standards, instead, included with the IRO Standards where it would be intuitive for operations staff to reference.

IRO-008-3 R5

IRO-008-3 R5 provides expectations of operations staff in real-time communication requirements needed to facilitate reliability. This Standard is intentionally, and properly, non-prescriptive in specific aspects of real-time or anticipated SOL risks, and does not introduce “risk-based” prescriptive actions for specific SOL events.

The SPP Standards Review Group considers IRO-008-3 R5 sufficient in requiring coordination and communication between entities that take place during SOL and IROL events. If necessary to document SOL methodologies that include the communication and coordination during such events, the SPP Standards Review Group recommends the methodologies should not be more descriptive than IRO-008-3 R5.

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

Requirement R7 of FAC-011-4 as currently written only provides the ability for a “risk based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated”, it does not seem to provide a risk based approach to how SOL exceedances are identified. If the intent is to provide the ability to use a risk based approach to determine how SOL exceedances are identified the language should be modified to make this clear. Requirement R7 could be reworded to say:

“Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances are identified as part of Real-time monitoring and Real-time Assessments and how they must be communicated and if so, the timeframe that communications must occur.”

If it is not the intent of the SDT to allow the identification of SOL exceedances to be risk based, requirement R7 may provide some relief from communication requirements that could be burdensome depending on the Reliability Coordinators’s SOL methodology, however it does not change that fact that Requirement 6 now makes any post contingent flow projected above a Facilities highest Emergency Rating an SOL exceedance. Some existing SOL methodologies allow for post contingent mitigation actions to be developed within 30 minutes in order to prevent this situation from becoming an SOL exceedance. It does seem appropriate that post contingent flow above the highest emergency rating would be an SOL exceedance, however this would be more stringent than what some have today and require more tracking, documentation, and communication. Consequently, the 12 month implementation timeframe would be insufficient to implement the new requirements and therefore request that the SDT extend the implementation plan to at least 24 months.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

In our opinion a 30 month implementation would be better because an entity may need to purchase new servers, or hardware, and software to meet logging obligations. We are concerned with the burden of providing exceedances due to the level of detail required from our ISO that will also become our responsibility. We believe that a large amount of work will be required to document and log what is expected to be a much larger number of exceedances under the proposed new FAC-011-04 and TOP-001-6 Reliability Standards.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 1, 5, 3, 6; Bryan Taggart, Westar Energy, 1, 5, 3, 6; Derek Brown, Westar Energy, 1, 5, 3, 6; Grant Wilkerson, Westar Energy, 1, 5, 3, 6; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., ; James McBee, Westar Energy, 1, 5, 3, 6; Marcus Moor, Westar Energy, 1, 5, 3, 6; - Douglas Webb, Group Name Westar-KCPL

Answer	No
Document Name	

Comment	

The Evergy companies do not support the proposed revision to FAC-011-4, TOP-001-6 and IRO-008-3 to address compliance risk and administrative logging.

The revisions are ambiguous and proposed requirements unsustainable.

There is inconsistency between R6.2 and R6.2.1, with the proposed language being confusing.

Moreover, having both Normal Ratings and Emergency Ratings calculated under FAC-008, and, also, entities being required to use both Normal Ratings and Emergency Ratings, is concerning: The revision would require operating at an Emergency Rating for a specified amount of time "*under a no contingency scenario*" rather than the current practice of operating up to an emergency rating indefinitely.

Finally, the Evergy companies support, and incorporate by reference, Edison Electric Institute's response to Question No. 2.

Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

BPA believes the proposed FAC-011-4 R7 is both too prescriptive and belongs in a TOP standard and Reliability Coordinator procedures developed under IRO-010. IRO-010 requires the Reliability Coordinator to document the information it needs to perform real-time monitoring, and this level of detail would be better left to that documentation. In addition to RC documentation, BPA believes the drafting team's objective of minimizing burdensome notifications can be achieved through the following proposed edit to TOP-001 R15 (bold, italic text added):

R15. Each Transmission Operator shall inform its Reliability Coordinator ***of SOL exceedances determined by its Reliability Coordinator's business procedures to merit notification.***

Likes 0	
Dislikes 0	
Response	

Anthony Jablonski - ReliabilityFirst - 10

Answer	No
Document Name	
Comment	

ReliabilityFirst offers the following comments on FAC-011-4 for the SDT's consideration. In the clean version of FAC-011-4, in the "New or Modified Term(s) Used in NERC Reliability Standards" section of the Standard, it states: "None." The term "System Operating Limit" has been modified and "System Voltage Limit" is newly defined.

Requirement R6 part 6.1.4, part 6.2.4, and part 6.3 references: "Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur." What is the meaning of "that adversely impact the reliability of the Bulk Electric System does not occur?" Is it possible for instability, Cascading, or uncontrolled separation to NOT adversely impact the reliability of the BES? What is the criteria for determining if instability, Cascading, or uncontrolled separation do or do not adversely impact the reliability of the BES? These parts of Requirement R6 are open to interpretation, and therefore does not promote the reliability of the BES. Note that the NERC approved definition of IROL also uses the term "… that adversely impact the reliability of the Bulk Electric System."

Requirement R7 does not specify which entities (TOPs? BAs? DPs?, etc.) are to be the receivers of the referenced communications of SOL exceedances. The "timeframe that communications must occur" are left to the discretion of the RC. The Requirement should be revised to clarify which entities the RC must communicate SOL exceedances to, and to specify a timeframe for the communication (of SOL exceedances) to occur.

FAC-011-4 requires the RC to have a SOL methodology and to provide the methodology to other entities (including TOPs within the RC area). TOPs are required (per FAC-014) to establish SOLs consistent with the RC's SOL methodology. The RC's SOL methodology typically specifies that the model to be used covers the entire RC footprint, as well as at least portions of adjacent RC's footprints. TOPs should not be required to follow an RC's SOL methodology to include a model that covers the entire RC (and portions of adjacent RC's) footprint. TOPs don't typically have models this large.

Likes 0	
Dislikes 0	

Response

Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System

Answer	No
Document Name	

Comment

LES feels that the sub-requirements listed in R7 may cause confusion as they relate to the performance criteria of R6. Suggest changing the word "of" to "based on", which will allow for a distinct correlation between what is and isn't a SOL exceedance. For example, 7.1.4 could be read as an independent check against Facility Ratings, which would raise the question whether it relates to Normal or Emergency Ratings. SOL exceedances should only be declared based on the performance criteria.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 3,4,5,6

Answer	No
Document Name	

Comment

NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.

Likes 0	
Dislikes 0	

Response

John Allen - City Utilities of Springfield, Missouri - 4

Answer	No
Document Name	

Comment

Besides the concerns expressed in response to question 1, what is the purpose of communicating SOL exceedances to the Reliability Coordinator? If the purpose is for the Reliability Coordinator's Real-time monitoring and/or Real-time Assessments, then the data specification concept is a more effective and efficient method and should be maintained in IRO-010-2 where each Reliability Coordinator has the flexibility to determine the items that need reported, the method and a timeframe based on their individual operating environment. Having this requirement detached in FAC-011 could lead to misunderstanding of context, expectations and/or compliance failures, which is contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements, reduce administrative burdens and remove redundancies. If not used for the Reliability Coordinator's Real-time monitoring and/or Real-time Assessments, then please explain the purpose and the corresponding obligation by the Reliability Coordinator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distract our operations personnel and doesn't benefit reliability.

R7.2.2. Please explain the rationale for 30 minutes for this one specific item when (according to R6.1 and further explained in the System Operating Limit Definition and Exceedance Clarification whitepaper) pre-contingency exceedances of much shorter timeframes are an indication of unacceptable system performance? This requirement seems to imply the risk of high voltage is minimal for all registered entities and their equipment.

Likes 0	
Dislikes 0	

Response

Truong Le - Truong Le On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 5, 3; Chris Gowder, Florida Municipal Power Agency, 6, 4, 5, 3; Dale Ray, Florida Municipal Power Agency, 6, 4, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 5, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Truong Le

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Maurice Paulk - Cleco Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See SEE, EEI and MISO comments	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	Project 2015-09_SOLs Comment_Form-Final.docx
Comment	

"These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments".

The MRO NSRF agrees with the changes proposed by the SDT to FAC-011-4, TOP-001-6 and IRO-008-3. That said, MISO requests the SDT acknowledge that momentary errors or other specified short-term excursions above Emergency Limits will occur and be dispositioned in accordance with the RC's SOL methodology. We would like to see this clarification in either the measures in the standard, the RSAW or Compliance Guidance

In addition, MRO NSRF requests the SDT consider implementing the clarifications below. Note that each request is presented independently for ease of review; however, when viewed collectively, there some requirements which would benefit from multiple clarifications that are additive:

Proposed Language (to clarify the description, if our interpretation of the SDT's intent is correct):

FAC-011-4, R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOLs exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses

Proposed Language (to clarify what is intended; as currently written, exceeding the normal low System Voltage Limit could be interpreted as operating at a higher voltage than the minimum [i.e. exceeding the limit] which would not necessarily have adverse impacts unless the operating voltage was also exceeding the high System Voltage Limit):

FAC-011-4, R7.1.5. Pre-contingency operating conditions outside SOL exceedances of normal low System Voltage Limits."

FAC-011-4, R7.2.1. Post-contingency operating conditions outside SOL exceedances of Facility Ratings and emergency System Voltage limits, and

Proposed Language (to add clarity by adding a reference to the corresponding description under FAC-011, requirement R6, if our interpretation of the SDT's intent is correct):

FAC-011-4, 7.1.4 "Facility Ratings as described in Part 6.1.1"

FAC-011-4, 7.2.1 "Facility Ratings as described in Part 6.2.1"

Proposed Language (to eliminate the potential interpretation that both parts 7.1.4 *and* 7.1.5 need to be true before the communication threshold is reached):

FAC-011-4, 7.1.4 "Pre-contingency SOL exceedances of Facility Ratings; and"

Proposed Language (to eliminate potential interpretation that use of the word "and" indicates both parts need to be true):

FAC-011-4, 7.2.1 "Post-contingency SOL exceedances of Facility Ratings; and emergency System Voltage limits, and"

7.2.2. Post-contingency SOL exceedances of emergency System Voltage Limits;

7.2.3. Pre-contingency SOL exceedances of normal high System Voltage Limits

Likes 0	
Dislikes 0	

Response

Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey

Answer	Yes
Document Name	

Comment

Generally, PG&E has no objections to the revisions, but has some concerns with implementation for FAC-011-4.

Likes 0	
Dislikes 0	

Response

Wayne Guttormson - SaskPower - 1

Answer	Yes
Document Name	

Comment

Support the MRO-NSRF comments.

Likes 0	
Dislikes 0	

Response

Jamie Johnson - California ISO - 2

Answer	Yes
Document Name	

Comment

California ISO agrees with comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	Yes
Document Name	

Comment

MISO supports the comments filed by the IRC SRC.

The IRC SRC agrees with the changes proposed by the SDT to FAC-011-4, TOP-001-6 and IRO-008-3. That said, the IRC SRC requests the SDT acknowledge that momentary errors or other specified short-term excursions above Emergency Limits will occur and be dispositioned in accordance with the RC's SOL methodology. We would like to see this clarification in either the measures in the standard, the RSAW or Compliance Guidance.

In addition, the IRC SRC requests the SDT consider implementing the following clarifications:

Proposed Language (if our interpretation of the SDT's intent is correct):

FAC-011-4, 7.1.4 "Facility Ratings as described in Part 6.1.1"

FAC-011-4, 7.2.1 "Facility Ratings as described in Part 6.2.1"

Proposed Language (to eliminate the potential interpretation that both parts 7.1.4 and 7.1.5 need to be true):

FAC-011-4, 7.1.4 "Pre-contingency SOL exceedances of Facility Ratings;"

Proposed Language (to eliminate potential interpretation that use of the word “and” indicates both parts need to be true):

FAC-011-4, 7.2.1 Post-contingency SOL exceedances of Facility Ratings;

7.2.2. Post-contingency SOL exceedances of emergency System Voltage Limits;

7.2.3. Pre-contingency SOL exceedances of normal high System Voltage Limits

Likes 0	
Dislikes 0	
Response	

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	Yes
Document Name	
Comment	

The IRC SRC agrees with the changes proposed by the SDT to FAC-011-4, TOP-001-6 and IRO-008-3. That said, the IRC SRC requests the SDT acknowledge that momentary errors or other specified short-term excursions above Emergency Limits will occur and be dispositioned in accordance with the RC’s SOL methodology. We would like to see this clarification in either the measures in the standard, the RSAW or Compliance Guidance.

In addition, the IRC SRC requests the SDT consider implementing the following clarifications:

Proposed Language (if our interpretation of the SDT’s intent is correct):

FAC-011-4, 7.1.4 “Facility Ratings ***as described in Part 6.1.1***”

FAC-011-4, 7.2.1 “Facility Ratings ***as described in Part 6.2.1***”

Proposed Language (to eliminate the potential interpretation that both parts 7.1.4 and 7.1.5 need to be true by removing the word 'and'):

FAC-011-4, 7.1.4 “Pre-contingency SOL exceedances of Facility Ratings; ***(delete and)***”

Proposed Language (to eliminate potential interpretation that use of the word “and” indicates both parts need to be true):

FAC-011-4, 7.2.1 “Post-contingency SOL exceedances of Facility Ratings***;(Delete - and emergency System Voltage limits, and)“***

7.2.2. ***Post-contingency SOL exceedances of*** emergency System Voltage Limits;

7.2.3. Pre-contingency SOL exceedances of normal high System Voltage Limits

Likes 0	
Dislikes 0	
Response	
Lee Maurer - Oncor Electric Delivery - 1	
Answer	Yes
Document Name	
Comment	

Oncor supports EEI comments.

Likes 0	
Dislikes 0	
Response	
Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	

IPL feels the industry needs more time with the implementation schedule to address coordination adjustments between RCs & TOPs to integrate the revisions of the RC's SOL methodology based on the updated framework. This could involve monitoring and system updates for efficient data transfers (automatic logging and reporting) to make these additional reporting requirements manageable for System Operators and Compliance Staff, and of course keeping the compliance records between the TOP and RC in lock-step.

The implementation plan document states that the "TOP-001-6" and "IRO-008-3" versions will be retired. IPL believes these are typos (meant to list the older versions of TOP-001-5/IRO-008-2), the SDT will need to revise this document to provide the plan for TOP-001-6 and IRO-008-3.

Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	

Comment	
EEI supports the inclusion of Requirement R7, which provides the industry with a risk-based approach for determining how SOL exceedances are identified, and how they are communicated, including timeframes. However, the implementation timeframe should be increased to allow for the increased burden of both identifying and validating exceedances. The SDT should modify the implementation plan to provide at least 24 months to allow the industry to address the proposed changes.	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports the inclusion of Requirement R7, which provides the industry with a risk-based approach for determining how SOL exceedances are identified, and how they are communicated, including timeframes, however; this does not fully address Southern Company’s specific concerns noted in Question 1 on the requirement revisions related to the establishment of limits, contingency events, and performance framework in FAC-011-4.	
Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1	
Answer	Yes

Document Name	
Comment	

On behalf of Exelon, Segments 1, 3, 5, & 6

Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	
Response	

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	

NV Energy supports the following comments provided by EEI:

EEI supports the inclusion of Requirement R7, which provides the industry with a risk -based approach for determining how SOL exceedances are identified, and how they are communicated, including timeframes. However, the implementation timeframe should be increased to allow for the increased burden of both identifying and validating exceedances. The SDT should modify the implementation plan to provide at least 24 months to allow the industry to address the proposed changes.

Likes 0	
Dislikes 0	
Response	

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	

CenterPoint Energy Houston Electric, LLC supports the comments as submitted by EEI.

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 Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
Please consider a 24 calendar month implementation plan, instead of 12 calendar months. Additional tracking, validation, and documentation of exceedances will be necessary. Enhancements to existing tracking tools may be required.	
Likes 0	
Dislikes 0	
Response	

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	

ATC believes the existing language of R7 may be adequate. However, we think some additional clarity on two specific requirements (R7.1.4 and R7.2.1) would benefit the industry. Both items relate back to how FAC-011-4 Requirement 7 does or does not tie back to the language of Requirement 6. In these two requirements, the clarification requested is, which Facility Ratings are in view as explained below.

New Requirement R7.1.4 states, “Pre-contingency SOL exceedances of Facility Ratings”. Based on our reading of the draft standard, we believe the SDT is referring to the thermal Facility Ratings described in requirement R6.1.1 (i.e. Normal and Emergency Ratings). R6.1.1 reads, “Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.”

Similarly, requirement R7.2.1 reads, “Post-contingency SOL exceedances of Facility Ratings and emergency System Voltage limits”. We believe the SDT intends for “Facility Ratings” to correspond to the Facility Ratings described in R6.2.1 (“Steady State post-Contingency flow through Facilities are within applicable Emergency Ratings., provided that System adjustments could be executed and completed within the specified time duration of those Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility’s highest Emergency Rating.”)

Regardless as to whether or not ATC’s interpretation is correct, we believe the industry will benefit in the future from greater clarity. For example, if ATC’s interpretation is correct, the SDT could add wording such as, “Facility Ratings as described in R6.1.1” for R7.1.4 and “Facility Ratings as described in R6.2.1” for R7.2.1.

ATC also has one minor comment on the formatting of R7.1 and R7.2 requirements. The word “and” appears in different sub-requirements, as shown below. We request the SDT review if “and” is correct wording to use, since a reader may interpret that all these items may need to be simultaneously true before the threshold is reached for communicating. The clearest example is R7.2.1. ATC believes that removing “and” and splitting up R7.2.1 as follows may be beneficial:

7.1.4. Pre-contingency SOL exceedances of Facility Ratings; and

7.1.5. Pre-contingency SOL exceedances of normal low System Voltage Limits.

7.2.1. Post-contingency SOL exceedances of Facility Ratings and

7.2.2 Post-contingency SOL exceedances of emergency System Voltage limits, and

7.2.3. Pre-contingency SOL exceedances of normal high System Voltage Limits.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	Yes
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

1. The construct in the proposed FAC-0114 (and Requirement R6) maintains how System Operators generally define IROLs today, and the long-standing operating practice where the loss of small or radial portions of the system is acceptable provided the performance requirements are not violated for the remaining bulk power system.

The IESO suggests that the footnote to Requirement R6, sub-requirement 6.2.4 be expanded to include this industry practice, as follows:

Sub-requirement R 6.2.4:

" Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur"[Footnote 1}

[Footnote 1] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques. *Loss of small or radial portions of the system is acceptable provided the performance requirements are not violated for the remaining bulk power system.*

2. The IESO seek clarification as to what is meant by "*expected to produce more severe System impacts*" in R4 Sub-requirement 4.2?

Likes 0	
Dislikes 0	

Response

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	Yes
Document Name	

Comment

MEC Supports NSRF Comments

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	Yes
Document Name	

Comment

MEC supports MRO NSRF comments. The MRO NSRF agrees with the changes proposed by the SDT to FAC-011-4, TOP-001-6 and IRO-008-3. That said, MISO requests the SDT acknowledge that momentary errors or other specified short-term excursions above Emergency Limits will occur and be dispositioned in accordance with the RC's SOL methodology. We would like to see this clarification in either the measures in the standard, the RSAW or Compliance Guidance

In addition, MRO NSRF requests the SDT consider implementing the clarifications below. Note that each request is presented independently for ease of review; however, when viewed collectively, there some requirements which would benefit from multiple clarifications that are additive:

Proposed Language (to clarify the description, if our interpretation of the SDT's intent is correct):

FAC-011-4, R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOLs exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses

Proposed Language (to clarify what is intended; as currently written, exceeding the normal low System Voltage Limit could be interpreted as operating at a higher voltage than the minimum [i.e. exceeding the limit] which would not necessarily have adverse impacts unless the operating voltage was also exceeding the high System Voltage Limit):

FAC-011-4, R7.1.5. Pre-contingency operating conditions outside SOL exceedances of normal low System Voltage Limits."

FAC-011-4, R7.2.1. Post-contingency operating conditions outside SOL exceedances of Facility Ratings and emergency System Voltage limits, and

Proposed Language (to add clarity by adding a reference to the corresponding description under FAC-011, requirement R6, if our interpretation of the SDT's intent is correct):

FAC-011-4, 7.1.4 "Facility Ratings as described in Part 6.1.1"

FAC-011-4, 7.2.1 "Facility Ratings as described in Part 6.2.1"

Proposed Language (to eliminate the potential interpretation that both parts 7.1.4 *and* 7.1.5 need to be true before the communication threshold is reached):

FAC-011-4, 7.1.4 "Pre-contingency SOL exceedances of Facility Ratings; and"

Proposed Language (to eliminate potential interpretation that use of the word "and" indicates both parts need to be true):

FAC-011-4, 7.2.1 "Post-contingency SOL exceedances of Facility Ratings; and emergency System Voltage limits, and"

7.2.2. Post-contingency SOL exceedances of emergency System Voltage Limits;

7.2.3. Pre-contingency SOL exceedances of normal high System Voltage Limits

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	Yes
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes

Document Name	
Comment	
Duke Energy agrees with the revisions but due to the numerous methodologies, procedures, processes, tools, and training impacts associated with this Project, suggest extending implemenation period from 12 months to 30 months.	
Likes 0	
Dislikes 0	
Response	
Ray Jasicki - Xcel Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Glen Allegranza, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Hirchak - Cleco Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

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

Mark Holman - PJM Interconnection, L.L.C. - 2

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Courchesne - Michael Courchesne On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Michael Courchesne	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE has the following recommendations regarding communication as described in proposed FAC-011-4 Requirement R7.

- Specify to whom the SOL exceedances must be communicated.
- Add language to specify that communication of SOL exceedances includes prevention and mitigation (IRO-008-3 R6) and actions taken to return the System to within limits when a SOL has been exceeded (TOP-001-6 R15). Even if Part 7.1 SOL exceedance is mitigated within timeframes identified for communication of SOL exceedances, this information should be communicated.
- Add language to communicate post-Contingency SOL exceedances of “normal minimum System Voltage Limits” or “normal maximum System Voltage Limits”. An exceedance could occur for an extended amount of time with no communication which may jeopardize the reliability of the System when the next Contingency occurs.
- Specify the time duration for IROL exceedances to be communicated in Part 7.1.1. The NERC Glossary definition states that IROL Tv should not exceed 30 minutes. Texas RE recommends the SDT consider adding language that the RC should communicate IROL exceedances within 30 minutes rather than its discretion.
- Remove “Outages” after “Cascading” in Part 7.1.3 since “Cascading Outages” is not a defined term per the NERC Glossary.

- Capitalize “contingency” in Part 7.1.3 wherever used since it is a defined term in the NERC Glossary. This includes “pre-“ and “post-“ usages.
- Include a description of what “validated risk” in Part 7.1.3 means or when the risk should be validated. The case could exist where there could be “post-contingency SOL exceedances” identified but there is no defined duration (time period) for an RC to “validate” the risk. An RC could take hours to validate that a contingency could occur that violated an Emergency Rating (time duration in minutes perhaps) and not communicate that issue in a timeframe that supports reliable operations (and 7.2 does not alleviate the concern.)

Additionally, Texas RE inquires as to whether a post-contingency operating state is identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation, but it is determined the instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System, would this be required to be identified and communicated since it may not be an SOL exceedance per Part 6.4?

- Use the terms “normal minimum” and “normal high” in Part 7.1.5 to be consistent with the proposed definition of System Voltage Limit.
- Specify a timeframe for the RC to communicate SOL exceedances that are not resolved within 30 minutes in Parts 7.1 and 7.2. If the SOL exceedance is not communicated timely, multiple entities could be working to mitigate the issue and the actions could potentially conflict with each other. Affected entities should be coordinating so they know what is being done and will not affect each other. They should confirm what each is doing to mitigate the SOL exceedance. For example, the RC could be taking certain measures at the same time an LCC is taking different measures. If they are not communicating, this could lead to adverse effects.
- Capitalize “limits” in Part 7.1.2 since it is part of the proposed term System Voltage Limits.

Likes 0	
Dislikes 0	

Response

3. If you have any other comments regarding FAC-011-4 that you haven't already provided, please provide them here.

John Allen - City Utilities of Springfield, Missouri - 4	
Answer	
Document Name	
Comment	
The standards need to be results-based and define *a clear and measurable expected outcome* for all Registered Entities. By adding "*that adversely impact the reliability of the Bulk Electric System*" implies that some instability, Cascading or uncontrolled separation is acceptable. Who determines that threshold? The Reliability Coordinator in its SOL methodology? How do we ensure a consistent expectation and application for all Registered Entities?	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	
Document Name	
Comment	
NIPSCO believes the Implementation Plan Effective Date is short and should be increased from twelve (12) calendar months to **thirty-six (36) calendar months.** We will work with the **EMS** vendor to create a process for related logging. In addition to developing new processes, related **training** will need to be developed and delivered. Furthermore, MISO will develop and implement new **methodology** and protocols. **This will all require additional time.**	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.	
Likes 0	

Dislikes 0	

Response

Bruce Reimer - Manitoba Hydro - 1

Answer	
Document Name	

Comment

The changes to these standards place a considerable reporting requirement on SOL exceedance. Manitoba Hydro is requesting 30 month implementation period rather than, normal 12 months implementation period to work out SOL reporting methodology with the RC.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	

Comment

"These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments".

Please note that the NSRF has concerns that if the Implementation Plan is not adjusted to atleast 24 months that this may impact our Final Ballot of the Standards within this Project.

1. Extend the implementation timeframe - The MRO NSRF respectfully requests the SDT extend the timeframe for implementation from 12 to at least 24 calendar months to support the changes needed to comply with FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3. Some entities will need to enhance existing tools to accurately track, validate and reconcile what is expected to be a significantly larger number of documented SOL exceedances; particularly in those instances where the Reliability Coordinator (RC) is not also the Transmission Operator (TOP). To support this change, it is anticipated that companies will need to make certain enhancements to systems such as their energy management systems (EMS) and/or Real-time Contingency Analysis (RTCA) tools in order to accurately track and validate SOL exceedances. While many entities may already utilize these same tools to identify and track SOL exceedances, most will have to further enhance these tools if they use dynamic line ratings (e.g., ambient temperature ratings or wind speed adjusted ratings). It is our understanding that most EMS and RTCA systems are not currently set up to distinguish the validity of exceedances in these situations.

Aside from tools, implementation of the new standards will also require collaboration between the RC and its respective TOPs to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. Additionally, a 24-month implementation timeframe would provide the time needed to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production, particularly in light of the ongoing operational challenges associated with the COVID-19 pandemic and the anticipated demand this will place on EMS vendors as entities compete for limited resources. For these reasons, MRO NSRF is requesting the SDT consider extending the implementation timeframe to at least 24 months.

For this approach to be successful, the effective dates of FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 need to be synchronized so they coincide.

2. Coordinate common SOLs - The MRO NSRF respectfully requests the SDT to consider coordination of all common SOLs similar to what is proposed in **FAC-011-4, Part 3.5** which requires the SOL methodology to define the method for determining common System Voltage Limits between the RC and its TOPs, between adjacent TOPs, and between adjacent RCs within an interconnection.

3. Replace IROL language with "Adverse Reliability Impact" - The MRO NSRF respectfully requests the SDT replace language excerpted from the current IROL definition with the current definition of "Adverse Reliablity Impact" to indicate that no amount of instability, Cascading or uncontrolled separation is acceptable:

Proposed Language

FAC-011-4, Parts 6.1.4 and 6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System Adverse Reliability Impacts does not occur.

Footnote 1, page 5: Stability evaluations and assessments of instability, Cascading, and uncontrolled separation Adverse Reliability Impacts can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques

FAC-011-4, Part 6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System Adverse Reliability Impacts does not occur

FAC-011-4, Part 7.1.3. Post-contingency SOL exceedances that are identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation Adverse Reliability Impacts

Likes 0	
Dislikes 0	
Response	

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

Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8

Answer	
Document Name	
Comment	

R4.6: Please clarify. Consider adding language to clarify the intent of this requirement as stated in the rationale.

R4.7: Please clarify. Consider adding language to clarify the intent of this requirement as stated in the rationale. Consider adding "for post-contingency mitigation" are not allowed....

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

BC Hydro agrees with the proposed FAC-011-4 R6 provides clarity on SOL exceedances that may alleviate the need for a glossary definition and offers the following comments and suggestions:

FAC-011-4 R6.2.1

The addition of "Steady state-post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating" to "Steady State post-Contingency flow through Facilities within applicable Emergency Ratings" in Requirement 6.2.1 appears redundant and can possibly create confusion.

Please consider the following wording:

"Steady state-post-Contingency flow through a Facility must not be above the Facility's highest *applicable* Emergency Rating"

Rationale for "applicable" is to reflect that Emergency Ratings must also observe the time duration requirement in the RC's SOL Methodology, and also that the highest Emergency rating can change seasonally.

The currently proposed language in requirements R6.2.1 and R6.2.2 appears to imply a more nuanced post-contingency performance requirement for flow vs. voltage. As requirements R6.2.1 and R6.2.2 are conceptually the same, so BC Hydro suggest that the use of similar wording.

FAC-011-3 R3.4 "Identify the lowest allowable System Voltage Limit"

If RC is required to identify a specific low voltage limit across its entire RC area, this will likely be a theoretical limit, which may not address the reliability issues that exist in specific areas of the RC Area. Rather than prescribing a specific limit applicable across the system, a list of qualitative considerations for establishing voltage stability based SOLs could be included instead. These considerations may include under voltage load shedding schemes design, voltage instability, loss of synchronism etc), and other prescriptions in support of accurate modeling of post contingency powerflow (e.g. low voltage limit not lower than value that could cause load trip due to process controls or motor contactors dropping etc.).

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	
Document Name	
Comment	

MEC supports MRO NSRF comments. Please note that the NSRF has concerns that if the Implementation Plan is not adjusted to atleast 24 months that this may impact our Final Ballot of the Standards within this Project.months that this may impact our Final Ballot of the Standards within this Project.

1. Extend the implementation timeframe - The MRO NSRF respectfully requests the SDT extend the timeframe for implementation from 12 to at least 24 calendar months to support the changes needed to comply with FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3. Some entities will need to enhance existing tools to accurately track, validate and reconcile what is expected to be a significantly larger number of documented SOL exceedances; particularly in those instances where the Reliability Coordinator (RC) is not also the Transmission Operator (TOP). To support this change, it is anticipated that companies will need to make certain enhancements to systems such as their energy management systems (EMS) and/or Real-time Contingency Analysis (RTCA) tools in order to accurately track and validate SOL exceedances. While many entities may already utilize these same tools to identify and track SOL exceedances, most will have to further enhance these tools if they use dynamic line ratings (e.g., ambient temperature ratings or wind speed adjusted ratings). It is our understanding that most EMS and RTCA systems are not currently set up to distinguish the validity of exceedances in these situations.

Aside from tools, implementation of the new standards will also require collaboration between the RC and its respective TOPs to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. Additionally, a 24-month implementation timeframe would provide the time needed to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production, particularly in light of the ongoing operational challenges associated with the COVID-19 pandemic

and the anticipated demand this will place on EMS vendors as entities compete for limited resources. For these reasons, MRO NSRF is requesting the SDT consider extending the implementation timeframe to at least 24 months.

For this approach to be successful, the effective dates of FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 need to be synchronized so they coincide.

Likes 0	
Dislikes 0	

Response

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	
Document Name	

Comment

MEC Supports NSRF Comments

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	2015-09_Unofficial_Comment_Form_202006 - SOCO Comments Final.pdf
Comment	

In addition to the specific concerns noted in Question 1, Southern Company offers the following comments on the SOL exceedance determination, use, and communications in FAC-011-4:

1) Requirement 6.4 of FAC-011-4 should have additional clarity that the limitation on manual load shedding only refers to firm load consistent with FERC Order 693. Specifically, the following changes should be made

6.4 In determining the System's response to any Contingency identified in Requirement R5, planned manual **FIRM** load shedding is acceptable only after all other available System adjustments have been made.

2) Additionally, the SOL whitepaper, of which the implementation of FAC-011-4 is largely based, appears to mistakenly refer to TOP-001-3 instead of TOP-001-6 on page 6

3) Lastly, the NERC timehorizon and the SOL whitepaper should add an additional time horizon of "Day-Ahead Operations" that can be used to clearly delineate the horizon in which SOLs are established and applicable in FAC-011-4. Ideally, Operations Planning horizon would be slightly modified to prevent overlap, but as this may impact other standards, it would be acceptable to leave more broad if necessary. Specifically, the new horizon would be termed "Day-Ahead Operations – operating and resource plans within the day-ahead timeframe" and replace the Operations Planning Horizon applicability of R5 through R9.

Detailed comments are in the attached file with special formatting for clarity and emphasis where needed (strike-through, highlighting, etc.).

Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	
Document Name	
Comment	

OGE supports MRO-NSRF's recommendation to extend the timeframe for implementation from 12 to 24 calendar months.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
ATC supports the changes proposed for the FAC-011, FAC-014, IRO-008 and TOP-001 standards. However, the 12 month implementation timeframe should be extended to 30 months. This additional time is needed to allow for the following sequential actions: First, the RC will need to update its methodology (in the case of MISO, this will be through a stakeholder process). Second, the TOP will need to update its operating practices and procedures to follow the revised RC methodology. Finally, likely in parallel, the RC and TOP will need train staff to adhere to the new requirements and methodology and create new processes to ensure documentation is developed, either automatically or manually, as new SOL exceedances are managed as evidence of compliance.	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
Some industry stakeholders believe the implementation plan should be 18 months as opposed to 12 months.	

Likes 0	
Dislikes 0	

Response

Mark Holman - PJM Interconnection, L.L.C. - 2

Answer	
Document Name	

Comment

R4.2 A portion of the redline language, "*applicable to the establishment of stability limits*" is redundant to the language that starts the requirement. The existing language "*to meet the criteria specified in Part 4.1*" already addresses the "that are expected to produce more severe System impacts". Only focusing on "*its portion of the BES*" could permit an RC or TOP to ignore addressing impacts to their neighboring TOP/RC, and as such should be expanded or dropped.

Given the intent is to indicate that not all the contingencies captured within R5 are applicable and/or required in order to establish stability limits, the following suggested language mirrors similar clarifying contingency language proposed by the SDT for FAC-011-4 R6.3:

Proposed Language: *Require that stability limits are established to meet the criteria specified in Part 4.1 for applicable Contingencies identified in Requirement R5.*

R6.2.4 Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

Given that 6.2.4 is applicable only to System performance *following contingencies*, suggest that "does not" be replace with "would not".

· **Proposed Language:** *Instability, Cascading or uncontrolled separation that adversely impact the reliability of the BES would not occur.*

R7 The proposed language in R7 does not solely provide, as the rationale states, "a performance framework for determining SOL exceedances in the RC's SOL methodology." Rather, it provided a communication framework around those SOL exceedances deemed reportable. However, R7 does not indicate any requirement around the communication (from whom & to whom) beyond it being directed to take place by the RC's methodology, which could include an RC communicating internally to itself. The proposed language below proscribes a direction of communication. If the SDT would prefer the RC's methodology to spell out the communication path, then that need should be included in a sub-requirement of R7.

· **Proposed Language:** *Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining which SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated by the Transmission Operator or the Reliability Coordinator to impacted Transmission Operators or Reliability Coordinators, and if so, the timeframe that communications must occur. The approach shall include:*

Likes 0	
Dislikes 0	

Response

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

Texas RE has the following additional comments for proposed FAC-011-4:

- Stability is a defined term in the NERC Glossary, but is used throughout FAC-011 (e.g. stability limits, stability performance, steady-state voltage stability, angular stability) and is not capitalized. Texas RE recommends the SDT take steps to incorporate the defined term into the Standards, update the definition, or retire the definition as appropriate.
- The language of Requirement R2 could imply that the RC owns Facilities, which is not typical.
- Texas RE recommends revising Requirement R2 to match the language in the rationale. It should be revised to "…such that the Transmission Operator**s** and **their** Reliability Coordinator**(s)** use common Facility Ratings."
- Requirement R3.1 shows System Voltage Limit(s) as both singular and plural. Please review for correct grammar.
- Texas RE recommends including a minimum bar for stability performance criteria in Requirement R4. As written, the RC has unlimited discretion to determine performance criteria that is used to establish stability limits, which can lead to action not being taken unless there is an Emergency.
- Texas RE is concerned with the vague language in Part 4.2. The current language indicates an entity will be expected to clearly demonstrate how stability limits are "expected" to produce more "severe" System impacts, but there is no threshold provided for what "severe" is. This language could result in an entity indicating all impacts are the same and there are no stability limits needed.
- In Part 4.3, Texas RE recommends the SDT consider adding "or other Reliability Coordinators Areas within its Interconnection" unless it has an understanding that there is a need to confirm stability limits used in operations between RCs in different Interconnections. Part 4.5 is similar: "other Reliability Coordinator Areas within its Interconnection."
- Part 5.3 only requires the RC to "[d]escribe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-014-3, Requirement R7, to use in determining stability limits." Texas RE recommends including language within FAC-011 or FAC-014 to require the RC to provide justification when Contingency events provided per FAC-014-3 R7 are not used in determining stability limits.
- Texas RE noticed there is no discussion of thermal limits in FAC-011. Does the SDT agree that thermal Facility Ratings are thermal SOLs?

Likes 0	
Dislikes 0	
Response	

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

Comment
Requirement 6 lists language stating “that adversely impact the reliability of the BES” without detailing what is considered “adverse impact.” This introduces inconsistences among the industry.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	

Comment
AZPS does not consider the intent of R4.2 to be clear. The language “more servere” is broad and open to interpretation. AZPZ requests that the STD add additional clarifying language to R4.2. R4.2 Required that stability limits are established to meet the criteria specified in Part 4.1 for the contingencies identified in requirement R5 applicable to the establishment of stability limits that are expected to produce more severe system impacts on its portion of the BES. Additionally, AZPS supports the comments submitted by EEI regarding the need to extend the implementation dates for Requirements FAC-011-4 and TOP-001-6. AZPS agrees that entities will see an addition in workload to document and track what is expected to be a significantly larger number of documented exceedances under the proposed new FAC-011-04 and associated TOP-001-001-6. Companies will need to make certain enhancements to systems such as their energy management systems (EMS) and/or Real-time Contingency Analysis (RTCA) tools to accurately track and validate exceedances. While many entities may already utilize these tools to track exceedances, most will have to further enhance those tools if they are using dynamic line ratings (e.g., ambient temperature ratings or wind speed adjusted ratings). It is our understanding that most of the EMS and RTCA systems are not currently set up to distinguish the validity of exceedances in these situations. To address this issue, the industry will need time to make these adjustments. Consequently, the 12 month implementation timeframe would be insufficient to implement the new requirements and therefore request that the SDT extend the implementation plan to at least 24 months.

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 Regional Standards Committee	
Answer	
Document Name	

Comment

The addition of R4.7 in FAC-011-4 will have an impact on interconnection with lower system inertia such as the Québec Interconnection.

Because of its unique characteristics (main generation centers located in the north, remote from the main load centers in the south), The QI has no potential viable BES Island in underfrequency conditions. Therefore, the use of the UFLS Program does not relate to system separation.

The Quebec Variance in the NERC Standard PRC-006-3 reflects that situation.

As mentioned in the rationale box for PRC-006-3 requirement D.A.3, the UFLS Program is part of the Hydro-Québec TransÉnergie defense plan to cover extreme contingencies along with two other RAS. Therefore, taking into account the reality of the QI, the use of the UFLS Program would relate more to R4.6 rather than R4.7.

We respectfully request the SDT extend the timeframe for implementation from 12 to at least 24 calendar months to support the changes needed to comply with FAC-011-4, FAC-014-3, TOP-001-6, and IRO-008-3. Some entities will need to enhance existing tools to accurately track, validate, and reconcile SOL exceedances; particularly in those instances where the Reliability Coordinator (RC) is not also the Transmission Operator (TOP). In addition to tools, implementation of the new standards will require collaboration between the RC and its respective TOPs to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. Additionally, a 24-month implementation timeframe would provide the time needed to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production, particularly in light of the ongoing operational challenges associated with the COVID-19 pandemic and the anticipated demand this will place on EMS vendors as entities compete for limited resources. For these reasons, we are requesting the SDT consider extending the implementation timeframe to at least 24 months.

We would also like to suggest that additional clarity could be achieved by adding the additional phrase to FAC-011-4 R2, ‘ which type of owner-provided Facility Ratings are to be used...’.

The definition of SOL includes thermal, voltage, stability, and frequency (BAL) Operating Limits. FAC-011-4 explicitly talks about voltage and stability but is silent on thermal. We don’t believe the facility rating discussion addresses SOLs for thermal limitations. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Limit.

Likes 0	
Dislikes 0	

Response

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

The changes to this standard would place a considerable reporting requirement on SOL exceedance. Therefore, the implementation period of 12 months for the Reliability Coordinators and Transmission Operators/Transmission Owners to work out SOL reporting methodology should be extended to at least 24 months. Additionally, the changes to this standard places the obligation ont the Reliability Coordinator to communicate SOL exceedance; however, if the information is not used by the Reliability Coordinators for Real-time monitoring and/or Real-time Assessments, it could potentially become an administrative compliance exercise that distracts Real Time Operations

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 1, 5, 3, 6; Bryan Taggart, Westar Energy, 1, 5, 3, 6; Derek Brown, Westar Energy, 1, 5, 3, 6; Grant Wilkerson, Westar Energy, 1, 5, 3, 6; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., ; James McBee, Westar Energy, 1, 5, 3, 6; Marcus Moor, Westar Energy, 1, 5, 3, 6; - Douglas Webb, Group Name Westar-KCPL

Answer	
Document Name	

Comment

The Evergy companies support, and incorporate by reference, Edison Electric Institute's response to Question No. 3.

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	

Comment

NV Energy supports the following comments provided by EEI:

As stated in our comments for question 1 (above), changes to FAC-011-4 place a considerable reporting obligation on SOL exceedance. Therefore, the implementation period of 12 months for the Reliability Coordinators and Transmission Operators/Transmission Owners to develop new SOL reporting methodology and associated system enhancements merit extending the implementation period to at least 24 months. While this standard places the obligation on the Reliability Coordinator to communicate SOL exceedance; if the information is not used by the Reliability Coordinators for Real-time monitoring and/or Real-time Assessments, it could become potentially an administrative compliance exercise that distracts Real Time Operations personnel from focusing on reliability. These new obligations also could be inconsistent with the ongoing work of the NERC Standards Efficiency Review project.

Likes 0	

Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

On behalf of Exelon, Segments 1, 3, 5, & 6

Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group

Answer	
Document Name	

Comment

No Comment

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

As stated in our comments for question 1 (above), changes to FAC-011-4 place a considerable reporting obligation on SOL exceedance. Therefore, the implementation period of 12 months for the Reliability Coordinators and Transmission Operators/Transmission Owners to develop new SOL reporting methodology and associated system enhancements merit extending the implementation period to at least 24 months. While this standard places the obligation on the Reliability Coordinator to communicate SOL exceedance; if the information is not used by the Reliability Coordinators for Real-time monitoring and/or Real-time Assessments, it could become potentially an administrative compliance exercise that distracts Real Time Operations personnel from focusing on reliability. These new obligations also could be inconsistent with the ongoing work of the NERC Standards Efficiency Review project.

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

Requirement R3.5 implies that adjacent Transmission Operators need to have common System Voltage Limits. While theoretically this might seem appropriate, it should be up to the adjacent Transmission Operators to determine acceptable System Voltage Limits for their systems. The voltage limits of adjacent Transmission Operators don't necessarily need to be common, however ITC agrees that Reliability Coordinators should be utilizing the same System Voltage Limits as the Transmission Operators. We also believe that adjacent Transmission Operators should coordinate their individual System Voltage Limits rather than requiring common System Voltage Limits. The intent of the requirement should be reflected in the language.

Another option would be to modify Requirement R3.5 to say:

"Define the method for ensuring that System Voltage Limits are coordinated between Reliability Coordinators and Transmission Operators, and between adjacent Reliability Coordinators within an Interconnection."

Requirement R5 seems to imply that all single contingency events listed in Requirement R5.1.1 should be included in the set of contingency events for use in determining stability limits. However Requirement R4.2 indicates that stability limits are established for only the contingencies that are expected to produce more severe system impacts. Requirement R4.2 is more appropriate as it would be unduly burdensome to expect that stability simulations be performed for all of the contingencies listed in Requirement R5.1.1. Requirement R5 should be split to make it clear that only the contingencies that are expected to produce more severe system impacts need to be considered for determining stability limits while all single contingencies (identified in Requirement R5.1.1) should be considered when perfomring Operational Planning Analysis and Real-time Assessments.

Implementation of these modifications to the standards will require collaboration between some Reliability Coordinators and their respective Transmission Operators to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. The implementation timeframe should be extended to at least 24 months in order to provide more time to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production.

Likes 0	
Dislikes 0	

Response

Robert Hirchak - Cleco Corporation - 6	
Answer	
Document Name	
Comment	
Implementation plan of 12 months is too short to develop operator tools to track.See MISO and EEI comments.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	
The SPP Standards Review Group offers the following "***non-content***" considerations for SDT review: 1. Implementation of the "blue box" concept, as in previous standards development processes, which could give industry insight on proposed revisions. 2. Consideration of the concept could assist in a seamless transfer of information to the future Guideline and Technical Basis documentation.	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	
Document Name	
Comment	
n/a	
Likes 0	

Dislikes 0	

Response

Lee Maurer - Oncor Electric Delivery - 1

Answer	
Document Name	

Comment

Oncor supports EEI comments.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	
Document Name	

Comment

The IRC SRC respectfully requests the SDT extend the timeframe for implementation from 12 to at least 24 calendar months to support the changes needed to comly with FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3. Some entities will need to enhance existing tools to accurately track, validate and reconcile SOL exceedances; particularly in those instances where the Reliability Coordinator (RC) is not also the Transmisison Operator (TOP). In addition to tools, implementation of the new standards will require collaboration between the RC and its respective TOPs to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. Additionally, a 24-month implementation timeframe would provide the time needed to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production, particularly in light of the ongoing operational challenges associated with the COVID-19 pandemic and the anticipated demand this will place on EMS vendors as entities compete for limited resources. For these reasons, the IRC SRC is requesting the SDT consider extending the implementation timeframe to at least 24 months.

The IRC/SRC would also like to suggest that additional clarity could be achieved by adding the additional phrase to FAC-011-4 R2, ‘ which ***type of*** owner-provided Facility Ratings are to be used…’.

The definition for SOL includes thermal, voltage, stability and frequency (BAL) Operating Limits. FAC-011-4 explicitly talks about voltage and stability but is silent on thermal. We don’t believe the facility rating discussion addresses SOLs for thermal limitations. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Limit.

Requirement R5 is looking for a set of contingency for stability, RTA and OPA analysis. A set of contingencies can be a dynamic list based on system configuration (outages) that can change throughout the day or it's simply the list of all BES elements in the footprint. We believe it would add clarity if the requirement said, 'for a ***type*** of contingency for…'.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	
Document Name	

Comment

MISO supports the comments filed by the IRC SRC.

The IRC SRC respectfully requests the SDT extend the timeframe for implementation from 12 to at least 24 calendar months to support the changes needed to comly with FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3. Some entities will need to enhance existing tools to accurately track, validate and reconcile SOL exceedances; particularly in those instances where the Reliability Coordinator (RC) is not also the Transmisison Operator (TOP). In addition to tools, implementation of the new standards will require collaboration between the RC and its respective TOPs to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. Additionally, a 24-month implementation timeframe would provide the time needed to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production, particularly in light of the ongoing operational challenges associated with the COVID-19 pandemic and the anticipated demand this will place on EMS vendors as entities compete for limited resources. For these reasons, the IRC SRC is requesting the SDT consider extending the implementation timeframe to at least 24 months.

The IRC/SRC would also like to suggest that additional clarity could be achieved by adding the additional phrase to FAC-011-4 R2, ' which type of owner-provided Facility Ratings are to be used…'.

The definition for SOL includes thermal, voltage, stability and frequency (BAL) Operating Limits. FAC-011-4 explicitly talks about voltage and stability but is silent on thermal. We don't believe the facility rating discussion addresses SOLs for thermal limitations. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Limit.

Requirement R5 is looking for a set of contingency for stability, RTA and OPA analysis. A set of contingencies can be a dynamic list based on system configuration (outages) that can change throughout the day or it's simply the list of all BES elements in the footprint. We believe it would add clarity if the requirement said, 'for a type of contingency for…'.

Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment	
ERCOT suggests the implementation period be extended from 12 to 24 months in order to allow sufficient time to make necessary system changes.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
Requirement 6 lists language stating "that adversely impact the reliability of the BES" without detailing what is considered "adverse impact." This introduces inconsistences among the industry.	
Likes 0	
Dislikes 0	
Response	
Jamie Johnson - California ISO - 2	
Answer	
Document Name	
Comment	
California ISO agrees with comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	
Document Name	
Comment	

Support MRO-NSRF comments for:

1. Extend the implementation timeframe

2. Coordinate common SOLs

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment

Please see comments submitted by Edison Electric Institute

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	
Document Name	

Comment

Certainly in FAC-011-4 Requirement R6, but also in the proposed PRC-023-5, CIP-014-3, and FAC-014-3, the pairing of "expected to result in instances of instability, Cascading, or uncontrolled separation" with "that adversely impacts the reliability of the Bulk Electric System" is unnecessarily redundant given that the Glossary of Terms definition of Adverse Reliability Impact is frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection. It is not clear if the SDT intends for this language to mean anything other than "expected to result in instances of instability, Cascading, or uncontrolled separation." Additionally, the SDT is perpetuating the industry-wide ambiguity of the term "widespread" by invoking the reference (without capitalization) to "adversely impacts the reliability." A simple, logical change is to simply retain "expected to result in instances of instability, Cascading, or uncontrolled separation" and stop there

Likes 0	
Dislikes 0	

Response

Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey	
Answer	
Document Name	
Comment	
PG&E has no additional comments	
Likes 0	
Dislikes 0	
Response	

Marco Rios - Pacific Gas and Electric Company - 1	
Answer	
Document Name	
Comment	
PG&E has no additional comments.	
Likes 0	
Dislikes 0	
Response	

4. The SDT has received numerous comments on the new FAC-015-1 since the first posting. Acknowledging these comments, the SDT has withdrawn FAC-015-1 and consolidated its four requirements into three requirements (R6 – R8) in proposed FAC-014-3 that retain the minimum requirements the SDT believes will allow retirement of FAC-010 and maintain limit/criteria coordination between operations and planning. Do you agree with the proposed requirements R6 through R8 in FAC-014-3?

Marco Rios - Pacific Gas and Electric Company - 1	
Answer	No
Document Name	
Comment	

In concept, the proposed requirements for FAC-014-3 R6 to R8 are good, but the details need to be further developed. For instance, for R6, the RC can change their methodology at any time and the Transmission Planner will then be responsible to ensure that any more stringent criteria are then reflected in Planning studies, but the RC is required by FAC-011-4 R9 to provide its SOL methodology to PCs and TPs, so there should be adequate notification which would allow the TP to implement such changes in their next reliability assessment. The greatest concern, then, appears to be possible disconnects between Operating and Planning criteria that make it difficult to ensure compliance with R6 and leave certain aspects up to interpretation, such as differences in Facility Ratings used in Operations vs. Planning. The standard as currently written does not require the RC to accept and respond to feedback from other entities if the methodology is unclear, but R6 will require the PC and TP to correctly interpret the methodology for ratings, limits, and criteria. For R7 and R8, the concept of notification to TOPs/RCs (R7) and TOs/GOs (R8) is sound, but the implementation may not be straightforward. In R7, for instance, "instability" must be communicated – does this include small generators that lose synchronism for P1 events? How does an entity differentiate bad models from instability when compliance directly depends on notifications of such issues? Clear definitions of the terms involved here would be a significant improvement.

Likes 0	
Dislikes 0	
Response	

Jack Stamper - Clark Public Utilities - 3	
Answer	No
Document Name	
Comment	

FAC-015 seems as an attempt to provide for the PC to TP heirarchy that should exist. However, it appears that there is a lack of coordination between FAC-011, FAC-014, and FAC-015. The goal should be to keep establishment of the Operating and Planning Horizon planning assessment with the closest entity (i.e. the Transmission Planner) and have the results go up the chain (subject to review and approval) from the TP to the PC to the RC and down to the TOP.

The existing combination appears to include would that will not be used and is therefore wasting time and not accomplishing reliability.

Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1

Answer	No
Document Name	
Comment	

WAPA agrees with removing the redundancy of the proposed FAC-015-1 and part of the shift of those requirements to the revised FAC-014-3. However, the proposed FAC-014-3 Requirement R6 remains redundant to existing obligations of MOD-032-1 and TPL-001-4 (soon -5) Requirement R1. The proposed Requirement R6 establishes a significant Compliance risk to planning entities who seek to plan the future transmission System for expansion and load growth, and ignores that Facility Ratings of the moment may not exist in the future planned System. In the proposed Requirement R7, it is unclear what reliability objective is accomplished that is not redundant to the existing IRO-017-1 Requirements R3 and R4. Furthermore, if there is a need to modify TPL-001-4 (soon -5) Requirement R8 to address annual Planning Assessment distribution, it should be revised there. Finally, to reiterate the comment above, FAC-014-3 Requirement R8 is not clear about requiring Planning Coordinators to communicate that "big-3" impacts during a particular planning event (e.g. see Cascading during simulation of a P6 event) were ***observed*** versus that "big-3" impacts ***caused*** a failure to meet System performance requirements. Here, the SDT is making a different interpretation than most planning entities make regarding TPL-001-4 (soon -5). It is not simply that "big-3" impacts were observed; it is that the "big-3" impact required a Corrective Action Plan (CAP) because the Contingency caused a failure to meet System performance requirements of Table 1. In other words, for a P6 event that yields Cascading, the Table 1 performance requirements may allow shedding Non-Consequential Load as part of the allowable mitigations such that System performance requirements are met (and no CAP). WAPA requests that the SDT reconsider the incorporation of the planning entity requirements into FAC-014-3 and, if retained, clearly state the intended reliability objective to retaining them there.

Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	
Comment	

Please see comments submitted by Edison Electric Institute

Likes 0	
Dislikes 0	
Response	

Wayne Guttormson - SaskPower - 1

Answer	No
Document Name	

Comment	
Understand the good-faith intent of the SDT, but fundamentally the proposed requirements are TPL 001 based (and perhaps even FAC 008 based) and should be placed in the applicable standard if deemed acceptable. The draft standard appears to mandate the Facility Ratings, System steady-state voltage limits and stability criteria to be used by the PC/TP, as set by the RC/TOP methodology. It would probably be more effective to rewrite the drafted FAC-014 standard for the RC's/TOP's to provide their associated technical rationales (beyond a methodology) for the defined operating limits to the PC/TP for input into the TPL assessments. In general, having standards placing requirements for other standards (as a standards setting practice) risks creating confusion. Also support the MRO-NSRF comments. .	
Likes 0	
Dislikes 0	
Response	

Jamie Johnson - California ISO - 2	
Answer	No
Document Name	
Comment	

In addtion to comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee the CAISO has the following comments:

CAISO believes the three requirements (R6-R8) proposed for FAC-014-3 are all misplaced and are duplicative of other existing NERC requirements in the following NERC standards: IRO-017, MOD-032 and TPL-001 as described below. Keeping “like” requirements together in one standard will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion, avoid undue regulatory burden and support the efforts of the Standards Efficiency Review project. For these reasons, we believe that FAC-010 can still be retired even if FAC-015 is withdrawn without adding Requirements R6 to R8 in FAC-014-3. Accordingly, we recommend:

- Requirements R6 to R8 be removed from FAC-014-3
- The phrase “ and that Planning Assessment performance criteria is coordinated with these methodologies.” be removed from the Purpose (Section 3) of FAC-014-3
- The Planning Coordinator and the Transmission Planner be removed from the Applicablity Section.

FAC-014-3

We have an overall concern with the term Facility Rating as applied in these FAC Standards and the confusion with those used in the MOD Standards. Does the SDT really mean Thermal Operation Limits as developed from the Factility Ratings? This set of standards talks about Steady State Voltage Limits, Stability Limits, but is silent on Thermal Operation Limits. We believe it would provide more clarity if the term Applicable Facility Ratings Duration Criteria was used in place of Facility Rating.

FAC-014-3, R6

We believe FAC-014-3, R6, i.e. to implement a documented process for Facility Ratings, voltage limits and stability criteria, is duplicative of existing NERC Standard MOD-032-1 (R2), whose purpose is "To establish consistent modeling data requirements and reporting procedures [for each Transmission Owner, Transmission Service Provider, Generation owner, Resources Planner, and Balancing Authority]. TPL-001-4, R1 requires each Planning Coordinator and Transmission Planner to maintain models that use data consistent with that provided in accordance with the MOD-032 Standard that represent projected System conditions. TPL-001-5 further requires that Applicable Facility Ratings shall not be exceeded and that system adjustments are allowed to mitigate rating exceedances if such adjustments are executable within the time duration applicable to the Facility Ratings. If the SDT believes additional detail, such as a criteria regarding which of the Facility Ratings (30 min, 4 hour, continuous, etc.) are applicable under normal and emergency conditions is required, we suggest TPL-001-4 be updated to include those details/criteria so that all related requirements are located together. TPL 001-5 also requires the Planning Coordinator and Transmission Planner to establish system steady state voltages, post-Contingency voltage deviation and transient voltage response. Instead of making the RC's SOL methodology, which is typically developed entirely from the operations perspective without involvement of the PC(s) and TPs, binding on PCs and TPs, TPL-001-5 can be modified so that the RC is a party in the development of the criteria, possibly through a process that is led by Regional Reliability Organizations such as WECC.

As we noted above, keeping "like" requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

In addition, reading the proposed Requirement 6.2 of FAC-011-4, it doesn't appear that there is a material risk for the PC and TP to use less restrictive criteria than the RC that makes including Requirement R6 in FAC-014-3 necessary.[1]

[1] The system performance standards FAC-011-4 requires the RC to include in its SOL methodology are:

Ø System performance for no contingencies demonstrates flows and voltages are within normal ratings but emergency limits may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

Ø System performance for single contingencies demonstrates flow through facilities and voltages are within applicable Emergency Ratings and System Voltgae Limits. Steady steate post-Contingency flow through a facility must not be above the Facilitiy's highest Emergency Rating.

If FAC-014-3, requirement R6 is not retired, the IRC SRC requests that it be modified to either: (1) actually include the desired criteria, including the Applicable Facility Ratings Duration Criteria, in FAC-014-3 possibly using similar language as used in Requirement R6 of FAC-011-4 while maintaining consistency with the requirements in TPL-001-5 mentioned above, rather than leaving it to the RC's SOL methodology, or (2) to acknowledge that the determination of Facility Ratings is the responsibility of Generator Owners (GO) and Transmission Owners (TO) under FAC-008-3 as follows:

Proposed Language:

FAC-014-3, R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings criteria, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that represent projected System Operating Limits that are equally limiting or more limiting than the Facility Ratings, System steady-state Voltage Limits and stability criteria as determined by the Transmission Owners and Generator Owners in accordance with FAC-008 and provided to the PC via MOD-032, R2 and in accordance with their respective RC's SOL methodology (FAC-011-4, R9).

Likewise, the requirement for the PC to notify impacted entities and provide a technical rationale for the use of a less limiting Facility Rating in its Planning Assessment (under FAC-014-3, R6) is misplaced. Instead, the IRC SRC recommends FAC-008-3 be revised (*see* requirement R8) and expanded to require GOs and TOs notify applicable entities, including the PC, of planned upgrades that will increase a Facility Rating and modify FAC-014-3 to recognize this.

- The Planning Coordinator may use less limiting Facility Ratings as provided by the GO or TO (in accordance with FAC-008-3, R8), to recognize planned upgrades in the Near Term Transmisison Planning Horizon, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator

Alternatively, MOD-032, R3 could be updated to reflect this detail as MOD-032-1, R3, Part 3.1 already requires Balancing Authorities, Generator Owners, Load Serving Entities, Resource Planners, Transmission Owners and Transmission Service Providers to provide an explanation with a technical basis for the data.

If on the other hand it can be assumed that the SDT is referring to Applicable Facility Ratings Duration Criteria rather than individual Facility Ratings, System voltage limits rather than Facility specific voltage limits and system stability limits then the provision of technical rationale be limited to the Regional Reliability Organization (RRO) as part of the established compliance monitoring process rather than to multiple entities to avoid putting additional regulatory burden on PCs and TPs.

FAC-014-3, R7

We believe FAC-014-3, R7 is duplicative of existing NERC Standard IRO-017-1, R3 which obligates each Planning Coordinator and Transmission Planner to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest IRO-017-1, R3 or Requirement R8 of TPL-001-5 be updated so that this type of request is located in a single requirement or standard. Keeping “like” requirements together will retain the overall context of the requirements, increase effiiciency, minimize opportunities for confusion, avoid undue regulatory burden, and support the efforts of the Standards Efficiency Review project.

We believe FAC-014-3, R8 is duplicative of existing NERC Standard TPL-001-4, requirements R6 and R8 and IRO-017-1, R3 which collectively include the obligation for the Planning Coordinator and Transmission Planner to define and document when the Planning Assessment indicates the inability of the system to meet the performance requirements, including System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding and to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need to request this information. If the SDT believes additional detail is required, we suggest that IRO-017-1, R3 or TPL-001-5, R8 be updated so that this type of request is located in a single requirement or standard. Keeping “like” requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion, avoid placing undue regulatory burden on entities and support the efforts of the Standards Efficiency Review project. We strongly oppose the requirement to inform multiple entities including generator owners because, that could take planning engineers away from their core job. The existing FAC-014 limits such communication to the affected RC. We recommend that arrangement remain unchanged.

Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

With respect to Requirement R6, ERCOT believes the language contained in the prior draft of FAC-015 should be utilized. The current draft of FAC-014 seems to suggest that responsible entities must provide a technical rationale to each Transmission Planner, Transmission Operator, and Reliability Coordinator in the event of the utilization of a higher rating than was provided for an upgraded circuit. Accordingly, ERCOT suggests replacing the proposed language of Requirement R6 with the language previously utilized in Requirements R1, R2, and R3 of FAC-015.

With respect to Requirement R8, ERCOT believes the Planning Coordinator (PC) and Transmission Planner should communicate only the limited information each Transmission Owner and Generator Owner (GO) needs to know, not necessarily the full details regarding the nature of the instability, Cascading, or uncontrolled separation. ERCOT suggest the use of the following language in Requirement R8:

Each Planning Coordinator and each Transmission Planner shall provide an annual communication to Transmission Owners and Generation Owners that own Facilities that meet the following conditions:

1. The Facility is part of a planning event contingency that the Planning Coordinator or Transmission Planner has identified in its annual Planning Assessment would cause instability, uncontrolled separation or Cascading outages that adversely impact the reliability of the BES if a limit is exceeded; or

2. The Facility is part of a contingency associated with an established IROL or stability limit, which was provided to the Planning Coordinator or Transmission Planner under Requirement R5, Part 5.2.4.

ERCOT also suggests modifying the standards that utilize such information, which are part of this ballot/comment period, to include "Facilities identified in FAC-014" or "FAC-014-3, Requirement R8" as appropriate so that the facilities that must meet those requirements include part 2 suggested above.

ERCOT further notes that it intends to vote in favor of FAC-014-3, provided the foregoing suggested modifications are incorporated.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment

MISO supports the comments filed by the IRC SRC.

The IRC SRC believes the three requirements (R6-R8) proposed for FAC-014-3 are all misplaced and are duplicative of other existing NERC requirements in the following NERC standards: IRO-017, MOD-032 and TPL-001 as described below. For these reasons, we believe that FAC-010 can still be retired even if FAC-015 is withdrawn.

FAC-014-3

We have an overall concern with the term Facility Rating as applied in these FAC Standards and the confusion with those used in the MOD Standards. Does the SDT really mean Thermal Operation Limits as developed from the Factility Ratings? This set of standards talks about Steady State Voltage Limits, Stability Limits, but is silent on Thermal Operation Limits. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Rating.

FAC-014-3, R6

We believe FAC-014-3, R6, i.e. to implement a documented process for Facility Ratings, voltage limits and stability criteria, is duplicative of existing NERC Standard MOD-032-1 (R2) and TPL-001-4, R1 which require each Planning Coordinator and Transmission Planner to maintain models that represent projected System conditions. If the SDT believes additional detail is required, we suggest MOD-032 or TPL-001-4 be updated so that all related requirements are located together. Keeping “like” requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

If FAC-014-3, requirement R6 is not retired, the IRC SRC requests that it be modified to acknowledge that the determination of Facility Ratings is the responsibility of Generator Owners (GO) and Transmission Owners (TO) under FAC-008-3 as follows:

Proposed Language:

FAC-014-3, R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that represent projected System Operating Limits that are equally limiting or more limiting than the Facility Ratings, System steady-state Voltage Limits and stability criteria as determined by the Transmission Owners and Generator Owners in accordance with FAC-008 and provided to the PC via MOD-032, R2 and in accordance with their respective RC’s SOL methodology (FAC-011-4, R9).

Likewise, the requirement for the PC to notify impacted entities and provide a technical rationale for the use of a less limiting Facility Rating in its Planning Assessment (under FAC-014-3, R6) is misplaced. Instead, the IRC SRC recommends FAC-008-3 be revised (*see* requirement R8) and expanded to require GOs and TOs notify applicable entities, including the PC, of planned upgrades that will increase a Facility Rating and modify FAC-014-3 to recognize this.

- The Planning Coordinator may use less limiting Facility Ratings as provided by the GO or TO (in accordance with FAC-008-3, R8), to recognize planned upgrades in the Near Term Transmisison Planning Horizon, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator

Alternatively, MOD-032, R3 could be updated to reflect this detail as MOD-032-1, R3, Part 3.1 already requires Balancing Authorities, Generator Owners, Load Serving Entities, Resource Planners, Transmission Owners and Transmission Service Providers to provide an explanation with a technical basis for the data.

FAC-014-3, R7

We believe FAC-014-3, R7 is duplicative of existing NERC Standard IRO-017-1, R3 which obligates each Planning Coordinator and Transmission Planner to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest IRO-017-1, R3 be updated so that this type of request is located in a single requirement or standard. Keeping “like” requirements together will retain the overall context of the requirements, increase effiiciency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

FAC-014-3, R8

We believe FAC-014-3, R8 is duplicative of existing NERC Standard TPL-001-4, requirements R6 and R8 and IRO-017-1, R4 which collectively include the obligation for the Planning Coordinator and Transmission Planner to define and document when the Planning Assessment indicates the inability of the system to meet the performance requirements, including System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding and to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest that IRO-017-1, R3 be updated so that this type of request is located in a single requirement or standard. Keeping "like" requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	No
Document Name	

Comment

The IRC SRC believes the three requirements (R6-R8) proposed for FAC-014-3 are all misplaced and are duplicative of other existing NERC requirements in the following NERC standards: IRO-017, MOD-032 and TPL-001 as described below. For these reasons, we believe that FAC-010 can still be retired even if FAC-015 is withdrawn.

FAC-014-3

We have an overall concern with the term Facility Rating as applied in these FAC Standards and the confusion with those used in the MOD Standards. Does the SDT really mean Thermal Operation Limits as developed from the Factility Ratings? This set of standards talks about Steady State Voltage Limits, Stability Limits, but is silent on Thermal Operation Limits. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Rating.

FAC-014-3, R6

We believe FAC-014-3, R6, i.e. to implement a documented process for Facility Ratings, voltage limits and stability criteria, is duplicative of existing NERC Standard MOD-032-1 (R2) and TPL-001-4, R1 which require each Planning Coordinator and Transmission Planner to maintain models that represent projected System conditions. If the SDT believes additional detail is required, we suggest MOD-032 or TPL-001-4 be updated so that all related requirements are located together. Keeping "like" requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project

If FAC-014-3, requirement R6 is not retired, the IRC SRC requests that it be modified to acknowledge that the determination of Facility Ratings is the responsibility of Generator Owners (GO) and Transmission Owners (TO) under FAC-008-3 as follows:

Proposed Language:

FAC-014-3, R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that represent projected System Operating Limits that are equally limiting or more limiting than the ***(delete - criteria for)*** Facility Ratings, System ***steady-state*** Voltage Limits and stability ***criteria*** as ***determined by the Transmission Owners and Generator Owners in accordance with FAC-008 and provided to the PC via MOD-032, R2 and in accordance with their respective RC's SOL methodology (FAC-011-4, R9).***

Likewise, the requirement for the PC to notify impacted entities and provide a technical rationale for the use of a less limiting Facility Rating in its Planning Assessment (under FAC-014-3, R6) is misplaced. Instead, the IRC SRC recommends FAC-008-3 be revised (*see* requirement R8) and expanded to require GOs and TOs notify applicable entities, including the PC, of planned upgrades that will increase a Facility Rating and modify FAC-014-3 to recognize this.

· The Planning Coordinator may use less limiting Facility Ratings ***as provided by the GO or TO (in accordance with FAC-008-3, R8), to recognize planned upgrades in the Near Term Transmisison Planning Horizon***, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator

Alternatively, MOD-032, R3 could be updated to reflect this detail as MOD-032-1, R3, Part 3.1 already requires Balancing Authorities, Generator Owners, Load Serving Entities, Resource Planners, Transmission Owners and Transmission Service Providers to provide an explanation with a technical basis for the data.

FAC-014-3, R7

We believe FAC-014-3, R7 is duplicative of existing NERC Standard IRO-017-1, R3 which obligates each Planning Coordinator and Transmission Planner to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest IRO-017-1, R3 be updated so that this type of request is located in a single requirement or standard. Keeping "like" requirements together will retain the overall context of the requirements, increase effiiciency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

FAC-014-3, R8

We believe FAC-014-3, R8 is duplicative of existing NERC Standard TPL-001-4, requirements R6 and R8 and IRO-017-1, R4 which collectively include the obligation for the Planning Coordinator and Transmission Planner to define and document when the Planning Assessment indicates the inability of the system to meet the performance requirements, including System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding and to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest that IRO-017-1, R3 be updated so that this type of request is located in a single requirement or standard. Keeping "like" requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

Likes 0	
Dislikes 0	

Response

Lee Maurer - Oncor Electric Delivery - 1

Answer	No
Document Name	

Comment	
Oncor supports EEI comments.	
Likes 0	
Dislikes 0	
Response	

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

FAC-014-3 R6

The SPP Standards Review Group asks the SDTs consideration that coverage of FAC-014-3 is included in the data provided in MOD-032-1, and in the model building in TPL-001-4 R1, where the models contain Facility Ratings, System steady-state voltage limits, and stability criteria that are equally limiting or more limiting than the ones utilized by the Reliability Coordinator (RC).

The SPP Standards Review Group asks the SDTs consideration of these differences in the scope for TPL-001-4 R1.

The development of Facility Ratings is the responsibility of the Transmission Owner (TO) in accordance with FAC-008-3. To allow the Planning Coordinator (PC) or Transmission Planner (TP) to develop a "less limiting", "higher" Facility Rating, could lead to unrealistic and/or invalid Planning Assessments.

The PC and/or the TP should not have the ability to overrule the TOs capability to maintain conservative Facility Ratings in accordance with manufacturer recommendations to protect its personnel and equipment.

If the PCs and TPs want to adjust system models with a higher Facility Rating based on a proposed system upgrade, that is included in TPL-001-4 R1, Part 1.1.3.

FAC-014-3 R6, as written, could lead to the misunderstanding of the context, the expectations, and/or the compliance failures.

FAC-014-3 R7

The SPP Standards Review Group asks the SDTs consideration that TPL-001-4 R8 is for the PC and TP to share information on their annual Planning Assessments.

The SPP Standards Review Group recommends that the list of entities in TPL-001-4 R8 include RCs and TOPs the ability to request and receive the information.

FAC-014-3 R7, as written, could lead to the misunderstanding of the context, the expectations, and/or the compliance failures.

FAC-014-3 R8

The SPP Standards Review Group considers existing coverage of FAC-014-3 R8 in TPL-001-4 R8.

The SPP Standards Review Group recommends that the list of entities in FAC-014-3 R8 include TOs and Generator Owners (GOs) the ability to request and receive the information.

FAC-014-3 R8, as written, could lead to the misunderstanding of the context, the expectations, and/or the compliance failures.

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

The proposed requirements R7 and R8 in FAC-014-3 are unnecessary. Requirement R5 ensures that the Reliability Coordinators provide the Plannning Coordinators and Transmission Planners the SOLs for their respective areas. If instability is identified in the Planning Assessments which drives an SOL, it would be provided to the TOPs through instabilitie identified by requirement R5. If the identified instability does not require an SOL then providing that information to TOPs could lead to uncertantity as to what to do with the information. Many of the instabilities identified by Planning should be items strictly for the Planning Horizon, as Planning should be addressing them with Corrective Action Plans prior to them making it to become a Real Time Operating Horizon SOL issue.

FAC-014 Requirement R6 is more appropriately placed in the TPL-001 standard to avoid possible confusion in completing the task in finalizing the completion of the models needed for performing the Near Term Assessments. All of the other requirements for the models are identified in this standard.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

While EEI is supportive of the general concepts for Requirements R6 through R8, the language lacks sufficient clarity to address what results or outcomes are expected. Given this ambiguity, the outcomes could result in inconsistent application across the various regions. Moreover, the current language in these three requirements do not adequately conform to the tenant of a Results Based Standard. For these reasons, we cannot support the currently proposed draft of FAC-014-3 at this time.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

While Southern Company supports the removal of FAC-015-1, retirement of FAC-010, and inclusion of the requirements as contemplated in R6 through R8 of the proposed FAC-014-3, these requirements are best located in TPL-001, not FAC-014. The proposed FAC-014-3 “Establish and Communicate System Operating Limits” should cover the responsibilities related to SOLs, which no longer apply to near/long-term planning horizons. The communication of planning information by the TP and PCs should be appropriately housed in the TPL standard family to prevent confusion and cross pollination of standards.

Southern Company also suggests a modification to R7 of the proposed FAC-014-3 that will help focus the communication of any instabilities identified in the Planning Assessment to include only those contingency events which are the most impactful, as follows:

*R7 Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the near-Term Transmission Planning Horiozon, **using planning event contingencies only**, to each impacted Reliability Coordinator.*

FAC – 014 R7 and R8 could result in burdensome communication even if there isn’t any identified issues per the Planning Assessment to communicate. As such, we suggest the following language modifications:

Modify the last sentence of FAC-014 R7 from “This communication shall include:” to “This communication, which is required if any information in Part 7.1 – Part7.5 is identified, shall include:”

Modify the first sentence of FAC-014 R8 from “shall annually communicate any instability…” to “shall annually communicate if there is any identified instability…….”

Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	

Response

Michael Jones - National Grid USA - 1

Answer	No
Document Name	
Comment	

FAC-014-3 Requirements (R6 – R8) are not well aligned for inclusion in a FAC Standard and there are already similar requirements in TPL-001-4. Requirement R8 in FAC-014-3, which requires annual communication of any instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System identified in its Planning Assessment, appears to already be covered by requirement R8 in TPL-001-4. In addition, FAC-014-3 Requirements (R6 - R8) are only related to the Near-Term Transmission Planning Time Horizon. There appears to be a need for further clarification regarding the relevant Time Horizon(s) which reference: "Time Horizon: Long-term Planning."

Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1

Answer	No
Document Name	
Comment	

On behalf of Exelon, Segments 1, 3, 5, & 6

Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	
Response	

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	
Comment	

NV Energy does not agree with the proposed requirement R6 of FAC-014-3. The proposed requirement requires additional clarity on the potential opportunity of a RC creating a Facility Rating based upon its own SOL methodology, and removing the ownership provided to Entities through FAC-008-3. FAC-014-3 requirement R6, currently reads that each Planning Coordinator and Transmission Planner shall implement a process to use Facility Ratings…that are equally limiting or more limiting than the criteria for Facility Ratings…as described in its RC's SOL methodology. NV Energy currently interprets this this as the RC can create a Facility Rating based on its own SOL methodology. Under this interpretation of the requirement, NV Energy cannot approve the current draft of the requirement R6..

Additionally, the remainder of the Standard, FAC-014-3, states that the PC and TP may use less limiting Facility Ratings, if the Entity provides a technical rationale. NV Energy interprets the intention of this language that the TP can use a less limiting element (higher facility rating) than what the RC provides, but that isn't entirely clear in the requirement's current draft.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 1, 5, 3, 6; Bryan Taggart, Westar Energy, 1, 5, 3, 6; Derek Brown, Westar Energy, 1, 5, 3, 6; Grant Wilkerson, Westar Energy, 1, 5, 3, 6; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., ; James McBee, Westar Energy, 1, 5, 3, 6; Marcus Moor, Westar Energy, 1, 5, 3, 6; - Douglas Webb, Group Name Westar-KCPL	
Answer	No
Document Name	
Comment	
The Evergy companies support, and incorporate by reference, Edison Electric Institute's response to Question No. 4. Evergy would further respond: *Proposed Revisions Add Reliability Risk.* Transmission Owners are required to develop Facility Ratings under FAC-008. The proposed two bulleted subparts permit the Planning Coordinator or Transmission Planner to use "less limiting" (higher) Facility Ratings. Inconsistencies between FAC-008 Facility Ratings and ratings developed under the R6 bulleted subparts can lead to unrealistic Planning Assessments or invalidate Planning Assessments, altogether. The proposed bulleted subparts seek to address the described reliability risk by requiring PCs or TPs to submit a technical rationale to affected TPs, TOs, and RCs. The proposed revision to FAC-014-3 does not consider the possibility TPs, TOs, RCs not wanting to accept a risk posed by the technical rationale. As such, the PCs or TPs could effectively reject TP, TO, or RC concerns raised by the technical rationale and proceed to operate at the less limiting Facility Ratings, regardless of those concerns; for example, the Transmission Owner needing to maintain conservative Facility Ratings in accordance with manufacture recommendations to protect its personnel and equipment.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

The proposed Requirements R6-R8 in FAC-014-3 all require actions associated with the PC and TP annual Planning Assessment, which is required by TPL-001. If not already sufficiently addressed by the Requirements in TPL-001, we believe it would be better to address any additional actions associated with the annual Planning Assessment in a revision to TPL-001 to avoid requirement fragmentation between TPL-001 and FAC-014.

Likes 0	
Dislikes 0	

Response

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

The proposed FAC-014-3 Requirements R6 through R8 obligate the Planning Coordinator and Transmission Planner to share information on their annual Transmission Planning Assessments. The proposed requirements are redundant because Planning Coordinators and Transmission Planners are already required to share planning assessments under TPL-001-4, Requirement R8. Requirement R8 states: "**Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.**" The proposed requirements would be inefficient, increase administrative compliance responsibilities, and would be contrary to ongoing work of the NERC Standards Efficiency Review project.

Alternatively, if the SDT does not withdraw Requirements R6 through R8, the intent with regard to the Time Horizon must be clarified. SOLs applied to support the Operations Planning Time Horizon will be different than those applied to the Long-Term Planning Time Horizon. Stability limits identified by the Reliability Coordinator may become invalid in the Planning Time Horizon as new generation is potentially added in future power flow models. When this occurs, it is the Transmission Planner's and Planning Coordinator's stability limits that must be communicated to the Reliability Coordinator so that the Reliability Coordinator knows what to expect.

Also, the two bulleted items in the newly proposed Requirement R6 are troubling. The development of Facility Ratings is the responsibility of the Transmission Owner, per FAC-008. To allow the Planning Coordinator and Transmission Planner to develop a "less limiting" Facility Rating could result in inaccurate Operational and Transmission Planning Assessments. The Planning Coordinator or Transmission Planner should not be allowed to independently overrule the Transmission Owner's responsibility to develop Facility Ratings.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

BPA agrees with the withdrawal of FAC-015-1 and consolidating the requirements into FAC-014-3. However, BPA offers the following comments on the new Requirements.

FAC-014-3 Requirement R6: Facility Ratings are modeling data, as developed and reported in Standards FAC-008 and MOD-032. System steady-state voltage limits and stability criteria used in Planning Assessments are criteria developed and documented in annual system assessments required by Standard TPL-001.

BPA suggests including the following language (bold. italic text added) to add clarity to R6:

R6. Each Planning Coordinator and each Transmission Planner shall ***ensure that, when developing its steady-state modeling data requirements, Facility Ratings used in its Planning Assessment*** of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the criteria for Facility Ratings described in its respective Reliability Coordinator's SOL methodology. ***In addition, each Planning Coordinator and each Transmission Planner shall ensure that criteria developed and documented for System steady state voltage limits and stability performance for its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the criteria for System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology.***

FAC-014-3 Requirement 7: BPA believes it should only be necessary to communicate information for Corrective Action Plans to impacted Transmission Operators and Reliability Coordinators that adversely impact the reliability of the Bulk Electric System. This is also consistent with the SDT's response to comments from the previous posting.

BPA suggests including the following language (bold, italic text added) to add clarity to R7.

R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon ***that adversely impacts the reliability of the Bulk Electric System*** to each impacted transmission Operator and Reliability Coordinator.

Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	
Comment	

MPC supports comments submitted by the MRO NERC Standards Review Forum.

Likes 0	
Dislikes 0	
Response	

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE

Answer	No

Document Name	
Comment	

OGE supports the concerns expressed by MRO-NSRF on the proposed FAC-014 R6, R7 and R8. OGE believes that the proposed R6, R7 and R8 are duplicative of requirements in TPL-001-4.

Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

While the intent of the requirements in FAC-014 does not appear to be reflected in the actual words. These requirements are confusing and create ambiguity that could result in incomsistent results, especially with auditors.

Likes 0	
Dislikes 0	
Response	

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	No
Document Name	
Comment	

MEC Supports NSRF Comments

Likes 0	
Dislikes 0	
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	No
Document Name	

Comment

MEC supports MRO NSRF comments.

R6 Concerns

The NSRF does not support incorporating R6 into FAC-014 for the following reasons:

Duplicative. Proposed R6 is covered by the data required under MOD-032-1 and TPL-001-4 R1 model building which specifies that models "*shall represent projected System conditions.*"

Questions for SDT Consideration

1. Wouldn't the models already evaluate System conditions against Facility Ratings, System steady-state voltage limits and stability criteria that are equally limiting or more limiting than those used by the RC?

2. Today, if there are differences, they should fall within the TPL-001-4 R1 audit scope.

Adds Reliability Risk. Transmission Owners are required to develop Facility Ratings under FAC-008. The proposed two bulleted subparts permit the Planning Coordinator or Transmission Planner to develop "*less limiting*" (higher) Facility Ratings. Inconsistencies between FAC-008 Facility Ratings and ratings developed under the R6 bulleted subparts can lead to unrealistic Planning Assessments or invalidate Planning Assessments, altogether.

The proposed bulleted subparts seek to address the described reliability risk by requiring PCs or TPs to submit a technical rationale to affected TPs, TOs, and RCs. The proposed revision to FAC-014-3 does not consider the possibility TPs, TOs, RCs not wanting to accept a risk posed by the technical rationale. As such, the PCs or TPs could effectively reject TP, TO, or RC concerns raised by the technical rationale and proceed to operate at the less limiting Facility Ratings, regardless of those concerns; for example, the Transmission Owner needing to maintain conservative Facility Ratings in accordance with manufacture recommendations to protect its personnel and equipment.

We would note, however, if the Planning Coordinators and Transmission Planners want to adjust system models with a higher Facility Rating based on a proposed system upgrade, there is a path to do so under TPL-001-4 R1, Part 1.1.3. (*New planned Facilities and changes to existing Facilities*).

R7 Concerns

The NSRF does not support incorporating R7 into FAC-014 for the following reasons:

Duplicative. The information sharing under proposed R7 is already addressed under TPL-001-4 R8, which establishes the Planning Coordinator and Transmission Planner are required to share information as part of their annual Planning Assessment.

Recommendation. Revise TPL-001-4 R8 to permit Reliability Coordinators and Transmission Operators to request and receive the CAPs information as reflected in proposed FAC-014 R7.

R8 Concerns

The NSRF does not support incorporating R8 into FAC-014 for the following reasons:

Duplicative. The information sharing under proposed R8 is already addressed under TPL-001-4 R8, which establishes the Planning Coordinator and Transmission Planner are required to share information as part of their annual Planning Assessment.

Recommendation. Revise TPL-001-4 R8 to permit Transmission Owners and Generator Owners to request and receive the information in proposed FAC-014 R8, e.g. instability info, cascading and uncontrolled separation.

Clarification. It looks as if the rationale document for FAC-014 infers the sole purpose of this requirement is to facilitate compliance administration needs for the Transmission Owners and Generator Owners since they do not operate the system. If that is the intent, it would be helpful to clarify and unambiguously state that for purposes of transparency.

R6 R7 R8 Shared Concerns

Compliance Ambiguity. As stated, above, incorporating R6, R7, and R8 into FAC-014 creates inconsistencies within the context of the Standard, providing unclear performance expectations and ambiguity around potential noncompliance. As such, the proposed revisions are incompatible with the Standards Efficiency Review project's effort to reduce ambiguity around compliance.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	No
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Duke Energy recommends that FAC-014-3 R7 be modified to include the phrase "during the planning events" as an added measure of clarity. For example: R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified "during the planning events" in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator.

Additionally, due to the numerous methodologies, procedures, processes, tools, and training impacts associated with this Project, suggest extending implementation period from 12 months to 30 months.

Likes 0	

Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

AEP disagrees with incorporating R6-R8 into FAC-014 as currently proposed. It is not clear exactly what the SDT believes the benefits would be of such an approach. FAC-014 and its obligations have historically been centric to the Operations Planning Time Horizon, not the Near/Long Term Planning Horizon as currently proposed in these most recent revisions. To do so would change the original intent and purpose of FAC-014 into something more reminiscent of TPL-001. We believe the SDT needs to clarify their strategies and intentions regarding the "mixing" of these time horizons, and for them to further consider the unintentional impacts of making such changes. The "planning assessments" proposed in FAC-014 seem redundant to that which is already required under TPL-001. We believe the SDT needs to be clear as to the intent of R6-R8 with regard to the Time Horizon. SOLs applied to support Operations Planning Time Horizon will be different than those applied to the Long-Term Planning Time Horizon. If the intent is to ensure SOLs applied in the Operations Planning Time Horizon are incorporated in any Planning Assessments performed, the existing language does not accomplish this. An RC's stability limits may become obsolete and thus inapplicable in the planning time horizon as new generation is added. When this happens, it is rather the TP's and PC's stability limits that ought to be communicated to the RC so the RC knows what to expect in the future. If industry and the SDT believe that the obligations proposed in R6-R8 are indeed worth pursuing, it may be worth considering including them within a new FAC standard of their own.

The revised FAC-014 R6, R7, and R8 apply directly to the conduct and communication of planning assessments. While we recognize that TPL-001 is not within scope of the project's SAR, we believe such obligations are already captured as part of TPL-001.

FAC-014 R6 states "Each Planning Coordinator and each Transmission Planner shall implement a documented process", but it is not clear exactly where the creation of this documented process is/was originally required.

Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

"These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments".

R6 Concerns

The NSRF does not support incorporating R6 into FAC-014 for the following reasons:

Duplicative. Proposed R6 is covered by the data required under MOD-032-1 and TPL-001-4 R1 model building which specifies that models "*shall represent projected System conditions*."

Questions for SDT Consideration

1. Wouldn't the models already evaluate System conditions against Facility Ratings, System steady-state voltage limits and stability criteria that are equally limiting or more limiting than those used by the RC?

2. Today, if there are differences, they should fall within the TPL-001-4 R1 audit scope.

Adds Reliability Risk. Transmission Owners are required to develop Facility Ratings under FAC-008. The proposed two bulleted subparts permit the Planning Coordinator or Transmission Planner to develop "*less limiting*" (higher) Facility Ratings. Inconsistencies between FAC-008 Facility Ratings and ratings developed under the R6 bulleted subparts can lead to unrealistic Planning Assessments or invalidate Planning Assessments, altogether.

The proposed bulleted subparts seek to address the described reliability risk by requiring PCs or TPs to submit a technical rationale to affected TPs, TOs, and RCs. The proposed revision to FAC-014-3 does not consider the possibility TPs, TOs, RCs not wanting to accept a risk posed by the technical rationale. As such, the PCs or TPs could effectively reject TP, TO, or RC concerns raised by the technical rationale and proceed to operate at the less limiting Facility Ratings, regardless of those concerns; for example, the Transmission Owner needing to maintain conservative Facility Ratings in accordance with manufacture recommendations to protect its personnel and equipment.

We would note, however, if the Planning Coordinators and Transmission Planners want to adjust system models with a higher Facility Rating based on a proposed system upgrade, there is a path to do so under TPL-001-4 R1, Part 1.1.3. (*New planned Facilities and changes to existing Facilities*).

R7 Concerns

The NSRF does not support incorporating R7 into FAC-014 for the following reasons:

Duplicative. The information sharing under proposed R7 is already addressed under TPL-001-4 R8, which establishes the Planning Coordinator and Transmission Planner are required to share information as part of their annual Planning Assessment.

Recommendation. Revise TPL-001-4 R8 to permit Reliability Coordinators and Transmission Operators to request and receive the CAPs information as reflected in proposed FAC-014 R7.

R8 Concerns

The NSRF does not support incorporating R8 into FAC-014 for the following reasons:

Duplicative. The information sharing under proposed R8 is already addressed under TPL-001-4 R8, which establishes the Planning Coordinator and Transmission Planner are required to share information as part of their annual Planning Assessment.

Recommendation. Revise TPL-001-4 R8 to permit Transmission Owners and Generator Owners to request and receive the information in proposed FAC-014 R8, e.g. instability info, cascading and uncontrolled separation.

Clarification. It looks as if the rationale document for FAC-014 infers the sole purpose of this requirement is to facilitate compliance administration needs for the Transmission Owners and Generator Owners since they do not operate the system. If that is the intent, it would be helpful to clarify and unambiguously state that for purposes of transparency.

R6 R7 R8 Shared Concerns

Compliance Ambiguity. As stated, above, incorporating R6, R7, and R8 into FAC-014 creates inconsistencies within the context of the Standard, providing unclear performance expectations and ambiguity around potential noncompliance. As such, the proposed revisions are incompatible with the Standards Efficiency Review project's effort to reduce ambiguity around compliance.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	

Comment
NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.

Likes 0	
Dislikes 0	

Response

John Allen - City Utilities of Springfield, Missouri - 4	
Answer	No
Document Name	

Comment

R6. This requirement is out of place in FAC-014 and should already be covered in the data provided via MOD-032-1 and model building effort via TPL-001-4 R1, which specifies that models "*shall represent projected System conditions*". Therefore, why wouldn't the models already contain Facility Ratings, System steady-state voltage limits and stability criteria that are equally limiting or more limiting than those used by the Reliability Coordinator? If there are significant differences between how the system is being planned and how it's being operated, then that should be within the scope for auditing TPL-001-4 R1 today. Having this requirement detached in FAC-014 could lead to misunderstanding of context, expectations and/or compliance failures, which is not effective or efficient and contrary to ongoing work by the Standards Efficiency Review project.

Additionally, the two bulleted items are problematic since the development of Facility Ratings is the responsibility of the Transmission Owner in accordance with FAC-008. To allow the Planning Coordinator or Transmission Planner to develop a "*less limiting*" (higher) Facility Rating could lead to unrealistic and/or invalid Planning Assessments. The Planning Coordinator and/or Transmission Planner should not be allowed on their own to overrule the Transmission Owner's ability to maintain conservative Facility Ratings in accordance with manufacture recommendations to protect its personnel and equipment. However, if the Planning Coordinators and Transmission Planners want to adjust system models with a higher Facility Rating based on a proposed system upgrade, then that is already allowed via TPL-001-4 R1, Part 1.1.3. (*New planned Facilities and changes to existing Facilities*).

R7. This requirement is out of place in FAC-014 and should be covered in TPL-001-4 R8 where the requirement for the Planning Coordinator and Transmission Planner to share information on their annual Planning Assessment resides. Having this requirement detached in FAC-014 could lead to misunderstanding of context, expectations and/or compliance failures, which is not effective or efficient and contrary to ongoing work by the Standards Efficiency Review project. Therefore, the list of entities in TPL-001-4 R8 should be enhanced to allow Reliabilty Coordinators and Transmission Operators the ability to request and receive this information.

R8. This requirement is out of place in FAC-014 and should be covered in TPL-001-4 R8 where the requirement for the Planning Coordinator and Transmission Planner to share information on their annual Planning Assessment resides. Having this requirement detached in FAC-014 could lead to misunderstanding of context, expectations and/or compliance failures, which is not effective or efficient and contrary to ongoing work by the Standards Efficiency Review project. It also appears in the rationale document for FAC-014 the sole purpose of this requirement is to facilitate compliance administration needs for the Transmission Owners and Generator Owners. Therefore, the list of entities in TPL-001-4 R8 should be expanded to allow Transmission Owners and Generator Owners the ability to request and receive this information.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey

Answer	Yes
Document Name	

Comment

In concept, the proposed requirements for FAC-014-3 R6 to R8 are good, but the details need to be further developed. For instance, for R6, the RC can change their methodology at any time and the Transmission Planner will then be responsible to ensure that any more stringent criteria are then reflected in Planning studies, but the RC is required by FAC-011-4 R9 to provide its SOL methodology to PCs and TPs, so there should be adequate notification which would allow the TP to implement such changes in their next reliability assessment. The greatest concern, then, appears to be possible disconnects between Operating and Planning criteria that make it difficult to ensure compliance with R6 and leave certain aspects up to interpretation, such as differences in Facility Ratings used in Operations vs. Planning. The standard as currently written does not require the RC to accept and respond to feedback from other entities if the methodology is unclear, but R6 will require the PC and TP to correctly interpret the methodology for ratings, limits, and criteria. For R7 and R8, the concept of notification to TOPs/RCs (R7) and TOs/GOs (R8) is sound, but the implementation may not be straightforward. In R7, for instance, "instability" must be communicated – does this include small generators that lose synchronism for P1 events? How does an entity differentiate bad models from instability when compliance directly depends on notifications of such issues? Clear definitions of the terms involved here would be a significant improvement.

Likes 0	
Dislikes 0	
Response	
Maurice Paulk - Cleco Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See SEE, EEI and MISO comments	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
IPL offers no further comment.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes

Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
In our opinion we need to be careful that there is only one methodology for SOL's going forward. We agree with the proposed requirements but also suggests that the team consider instead adding these requirements within TPL-001, which deals with the Planning Assessment and correspondence/communication of the Planning Study to affected entities.	
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 Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
We have an overall concern with the term Facility Rating as applied in these FAC Standards and the confusion with those used in the MOD Standards. Does the SDT really mean Thermal Operation Limits as developed from the Facility Ratings? This set of standards talks about Steady State Voltage Limits, Stability Limits, but us silent on Thermal Operation Limits. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Limit.	
Likes 0	
Dislikes 0	
Response	

Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter	
Answer	Yes
Document Name	
Comment	

FAC-014-3 The statement “any instability identified in its Planning Assessment of the Near-Term Transmission…” seems unclear. I think an improvement and more clear statement might be, “any stability criteria violation identified in its Planning Assessment of the Near-Term Transmission…”.

The revision that Oncor is proposing also seems to better align with the deliverables outlined in R7.1 – R7.5, and in particular, R7.3: The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria).

Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

1. The IESO is concerned that there is no requirement for the affected RC to provide feedback on the technical rationale provided by the PC or TP for using less limiting ratings. The IESO proposes to add a sub-requirement to establish this feedback loop between the affected entities and the PC or TP. The proposed requirement would mirror Requirement R8, sub-requirement 8.1. of Reliability Standard TPL-001-4 which allows the recipient of the Planning Assessment results to provide documented comments on the results, and the respective PC or TP to provide a documented response to that recipient within 90 calendar days of receipt of those comments:

Proposed Requirement R6, Sub-requirement 6.1:

“The recipient of the technical rationale may provide documented comments on the results, and the respective PC or TP to provide a documented response to that recipient within 90 calendar days of receipt of those comments”

Alternatively, the IESO would like to clarify if Requirement R8., subrequirement 8.1 is the feedback loop that can be used to address the lack of input from the affected entities on the technical rationale provided by the PC or TP on the use of less limiting ratings (this is based on the assumption that the technical rationale would be part of the Planning Assessment results).

2. Similar with the Reliability Standard TPL-001-4 where an RC can provide input on the Planning Assessment criteria, the IESO believes that the PC and TP should be afforded the reciprocal opportunity to provide input to its RC's methodology and have the RC provide a document response.

The IESO proposes to add *Sub-requirement R9.3 to FAC-011-4 as follows:*

"9.3. If a recipient of the Reliability Coordinator SOL methodology provides documented comments on the methodology, the respective Reliability Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments."

3. We find that Requirements R7 and R8 are duplicative of existing communication requirements within other Reliability Standards. Specifically,

{C}o **Requirement R7 requires the PC and TP to communicate, annually any CAP identified in its Planning Assessments to the RC. Requirement 8 in TPL-001-4 requires the PC and TP to provide its Planning Asssessment results to affected entities, which include any CAP developed in R2 Sub-requirements 2.7 of TPL-001-4; and**

{C}o **Similarly, Requirement R8 requires the PC and TP to communicate, annually , any instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES in its Planning Assessment of the Near- Term Transmission Planning Horizon to TOs and GOs. All Planning Assessments performed by PCs and TPs are governed by other standards (TPL-001, PRC-012, PRC-023 etc.) and the processes required by those standards already include provisions for the communication of those results to the entities that have a reliability need.**

We suggest that Requirements R7 and R8 be removed to avoid duplication with existing communication obligations for the PC and TP.

Likes 0	
Dislikes 0	
Response	
Ray Jasicki - Xcel Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Glen Allegranza, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Hirchak - Cleco Corporation - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Truong Le - Truong Le On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 5, 3; Chris Gowder, Florida Municipal Power Agency, 6, 4, 5, 3; Dale Ray, Florida Municipal Power Agency, 6, 4, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 5, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Truong Le	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Courchesne - Michael Courchesne On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Michael Courchesne	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mickey Bellard - Seminole Electric Cooperative, Inc. - 1,5 - SERC	
Answer	
Document Name	FAC-014 SBS Comments 8-3-2020.docx
Comment	
Likes 0	
Dislikes 0	
Response	

5. If you have any other comments regarding FAC-014-3 that you haven't already provided, please provide them here.

John Allen - City Utilities of Springfield, Missouri - 4	
Answer	
Document Name	
Comment	

R3. What is the purpose of the Transmission Operator providing its SOLs to the Reliability Coordinator? If it's for the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring and Real-time assessments, then keeping this requirement is redundant with the data specification in IRO-010-2 and contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements, reduce administrative burdens and remove redundancies. If not used for the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring and/or Real-time Assessments, then please explain the purpose and the corresponding obligation by the Reliability Coordinator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

Furthermore, by definition SOLs change continuously based on "*a specified system configuration*". Therefore, does the SDT expect the Transmission Operator to continuously provide the Reliability Coordinator with updated SOLs for each system configuration within the timeframe of each Operational Planning Analysis, Real-time monitoring and/or Real-time Assessment? This is another reason why the information/data exchange activity needs to remain within IRO-010-2, where each Reliability Coordinator can determine the items that need reported, the method and a timeframe based on their individual operating environment.

R5.1 and R5.2. If one purpose of Project 2015-09 is to eliminate planning-based SOLs and IROLs, then what is the purpose of the Reliability Coordinator providing them to the Planning Coordinator and Transmission Planners in this requirement? If it's for the purpose of better aligning planning and operations, then where is the requirement for the Planning Coordinator or Transmission Planner to use them in the models for the Planning Assessments? If there isn't a corresponding obligation, then it potentially becomes an administrative compliance exercise that isn't benefiting reliability. Additionally, the model building topic is covered in MOD-032-1 and if the intent is to use additional information identified during operations in the models for TPL-001-4 Planning Assessments, then MOD-032-1 should be enhanced and the Reliability Coordinator should be added to the applicability. Having it dispersed in other standards could lead to misunderstanding of context, expectations and/or compliance failures, which is not effective or efficient.

R5.3 and R5.4. What is the purpose of the Reliability Coordinator providing IROL information to the Transmission Operators? If it's for the Transmission Operator's Operational Planning Analyses, Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive information from its Reliability Coordinator. To keep these requirements detached in FAC-014 is not effective or efficient and contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements, reduce administrative burdens and remove redundancies. If not used for the Transmission Operator's Operational Planning Analyses, Real-time monitoring and/or Real-time Assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

Likes 0	
Dislikes 0	
Response	

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	
Document Name	

Comment	
None	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	
It is also important that RC and/or TO provide technical rationale to PC if they are using less restrictive SOLs than PC's SOLs.	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

“These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments”.

R3 Issues

A. Transmission Operators providing their SOLs to the Reliability Coordinator raises some questions for consideration by the SDT:

1. Is SOL data sharing being used for the Reliability Coordinator’s Operational Planning Analyses, Real-time monitoring and Real-time assessments?

If that is the case, R3 is redundant with the data specification in IRO-010-2 and could be a candidate for deactivation under the Standards Efficiency Review project.

2. If SOL data sharing is not used by the RC for OPA, RTM and RTAs, what is the purpose of the data sharing, and the corresponding obligation by the Reliability Coordinator, to use the information?

Concern. Without a clear purpose and specific benefit to reliability of BPS, R3 saddles operations personnel with an administrative compliance burden that provides little reliability benefit.

B. SOLs, by definition, continuously change based on “*a specified system configuration*”.

1. Is the expectation for the Transmission Operator to continuously provide the Reliability Coordinator with updated SOLs for each system configuration within the timeframe of each Operational Planning Analysis, Real-time monitoring and/or Real-time Assessment?

This highlights why the information/data exchange topic probably needs to remain within IRO-010-2 where Reliability Coordinators can determine items that need to be reported, the method and a timeframe based on the RCs’ specific operating environment.

R5 Issues

A. Reliability Coordinators providing planning-based SOLs and IROLS to the Planning Coordinator and Transmission Planner raises some questions for consideration by the SDT:

1. What is the purpose of the Reliability Coordinator providing SOLs and IROLS to the Planning Coordinator and Transmission Planners?

If the purpose is to better align planning and operations, we are unaware of any requirement for the Planning Coordinator or Transmission Planner to use SOLs and IROLS in models for the Planning Assessments.

Concern. Without a clear requirement for the Planning Coordinator or Transmission Planner to use SOLs and IROLS in models for the Planning Assessments, R5 loads operations personnel with an administrative compliance burden that provides little reliability benefit.

2. Is the intent to use additional information--like SOLs and IROLs--identified during operations in the models for TPL-001-4 Planning Assessments?

If that is the case, MOD-032-1, the model building Standard, should be revised to expand the Applicability to include the Reliability Coordinator.

Compliance Challenge. Scattering model building Requirements across multiple Standards is inefficient, creating the opportunity for discord between Requirements, even difficulties agreeing on the guiding Requirement for purposes of compliance and enforcement. Clarity as to the expected or desired performance under a Requirement better serves BPS reliability.

B. Reliability Coordinators providing IROL information to the Transmission Operators raises some questions for consideration by the SDT:

1. Is IROL data sharing being used for the Transmission Operator’s Operational Planning Analyses, Real-time monitoring and Real-time assessments?

If that is the case, then the data specification concept should be maintained and TOP-003-3 revised to allow the Transmission Operator to request and receive the information from its Reliability Coordinator.

2. If IROL data is not used by the RC for OPA, RTM and RTAs, what is the purpose of the data sharing, and the corresponding obligation by the Reliability Coordinator, to use the information?

Concern. Without a clear purpose and specific benefit to BPS reliability, R5 encumbers operations personnel with an administrative compliance burden that provides little reliability benefit.

3. The NSRF does not support incorporating R5 into FAC-014. As outlined, above, the revision may be inconsistent with the Standards Efficiency Review project goals of simplifying data exchange requirements and addressing redundancies.

Purpose Statement Issue

The NSRF does not support adding the phrase, "…and that Planning Assessment performance criteria is coordinated with these methodologies," to the proposed FAC-014-3 Purpose statement.

As already discussed in our previous responses, we believe consolidating the four FAC-015 requirements into proposed FAC-014-3 R6, R7 and R8 creates redundant Requirements; the planning aspects of the proposed Requirements are represented within other Standards. As such, the proposed revision to the FAC-014-3 Purpose statement is unnecessary.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	
Document Name	

Comment

If retained, we believe FAC-014 should be revised as "Each Reliability Coordinator shall establish stability limits to be used in operations when *an instability* impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology."

Likes 0	
Dislikes 0	

Response

Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8

Answer	
Document Name	

Comment

R5.5: This language is awkward. Please clarify and reword to capture intent.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	
Document Name	
Comment	

MEC supports MRO NSRF comments.

R3 Issues

A. Transmission Operators providing their SOLs to the Reliability Coordinator raises some questions for consideration by the SDT:

1. Is SOL data sharing being used for the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring and Real-time assessments?

If that is the case, R3 is redundant with the data specification in IRO-010-2 and could be a candidate for deactivation under the Standards Efficiency Review project.

2. If SOL data sharing is not used by the RC for OPA, RTM and RTAs, what is the purpose of the data sharing, and the corresponding obligation by the Reliability Coordinator, to use the information?

Concern. Without a clear purpose and specific benefit to reliability of BPS, R3 saddles operations personnel with an administrative compliance burden that provides little reliability benefit.

B. SOLs, by definition, continuously change based on "*a specified system configuration*".

1. Is the expectation for the Transmission Operator to continuously provide the Reliability Coordinator with updated SOLs for each system configuration within the timeframe of each Operational Planning Analysis, Real-time monitoring and/or Real-time Assessment?

This highlights why the information/data exchange topic probably needs to remain within IRO-010-2 where Reliability Coordinators can determine items that need to be reported, the method and a timeframe based on the RCs' specific operating environment.

R5 Issues

A. Reliability Coordinators providing planning-based SOLs and IROLS to the Planning Coordinator and Transmission Planner raises some questions for consideration by the SDT:

1. What is the purpose of the Reliability Coordinator providing SOLs and IROLS to the Planning Coordinator and Transmission Planners?

If the purpose is to better align planning and operations, we are unaware of any requirement for the Planning Coordinator or Transmission Planner to use SOLs and IROLS in models for the Planning Assessments.

Concern. Without a clear requirement for the Planning Coordinator or Transmission Planner to use SOLs and IROLS in models for the Planning Assessments, R5 loads operations personnel with an administrative compliance burden that provides little reliability benefit.

2. Is the intent to use additional information--like SOLs and IROLs--identified during operations in the models for TPL-001-4 Planning Assessments?

If that is the case, MOD-032-1, the model building Standard, should be revised to expand the Applicability to include the Reliability Coordinator.

Compliance Challenge. Scattering model building Requirements across multiple Standards is inefficient, creating the opportunity for discord between Requirements, even difficulties agreeing on the guiding Requirement for purposes of compliance and enforcement. Clarity as to the expected or desired performance under a Requirement better serves BPS reliability.

B. Reliability Coordinators providing IROL information to the Transmission Operators raises some questions for consideration by the SDT:

1. Is IROL data sharing being used for the Transmission Operator's Operational Planning Analyses, Real-time monitoring and Real-time assessments?

If that is the case, then the data specification concept should be maintained and TOP-003-3 revised to allow the Transmission Operator to request and receive the information from its Reliability Coordinator.

2. If IROL data is not used by the RC for OPA, RTM and RTAs, what is the purpose of the data sharing, and the corresponding obligation by the Reliability Coordinator, to use the information?

Concern. Without a clear purpose and specific benefit to BPS reliability, R5 encumbers operations personnel with an administrative compliance burden that provides little reliability benefit.

3. The NSRF does not support incorporating R5 into FAC-014. As outlined, above, the revision may be inconsistent with the Standards Efficiency Review project goals of simplifying data exchange requirements and addressing redundancies.

Purpose Statement Issue

The NSRF does not support adding the phrase, "…and that Planning Assessment performance criteria is coordinated with these methodologies," to the proposed FAC-014-3 Purpose statement.

As already discussed in our previous responses, we believe consolidating the four FAC-015 requirements into proposed FAC-014-3 R6, R7 and R8 creates redundant Requirements; the planning aspects of the proposed Requirements are represented within other Standards. As such, the proposed revision to the FAC-014-3 Purpose statement is unnecessary.

Likes 0	
Dislikes 0	

Response

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	
Document Name	

Comment

MEC Supports NSRF Comments

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	2015-09_Unofficial_Comment_Form_202006 - SOCO Comments Final.pdf
Comment	
Detailed comments are in the attached file with special formatting for clarity and emphasis where needed (strike-through, highlighting, etc.).	
Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	

Comment	
Measure M3, the phrase "in accordance with its Reliability Coordinator's SOL methodology" should be stricken since it is stricken in the requirement. Proposed language "in accordance with requirement R3" would suffice.	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	
Document Name	
Comment	

R3 - The new language provides no suggested timeline beyond the Time Horizon of Operations Planning. Many SOLs, the limit itself, not the basis for the limit which can include Facility Ratings, at minimum, are derived/determined in the Real-time horizon. The Rationale gives several options/examples of how this might transpire which are not governed by the requirement language, which drops the suggested option of "*in accordance with its Reliability Coordinators SOL methodology*". As such, the proposed SDT language for R3 is ambiguous and either allows the TOP to indicate an SOL as they see fit, or continuously.

Yet, the measurement indicates that evidence demonstrating the TOP provided its SOLs in accordance with its RC's SOL methodology. Which seems appropriate.

R5 - RC's have Facility Ratings. RC's have stability limits. RC's have criteria for the determination of IROLs. The value of the SOL, which could include, for example a single temperature set rating for a given facility, is of minimal benefit to a PC or TP and is an incomplete set.

- The methodology and ratings sets that can lead to potential SOLs would be of value to the PC or TP.

As written, this requirement and many of its subparts serve minimal reliability value and is highly administrative in nature; and is not an improvement over the current FAC-014-2 R5. Requiring the formalized exchange of such information is not necessarily a determination that it is of value to the recipient.

Suggest R5 be rewritten to align with R6 and provided the criteria, methodology and supporting data (including Facility Ratings) that may be both relevant and beneficial to a TP or PC. Alternatively, providing a list of SOL exceedances and/or trends may also be of some value to the PC or TP. A long list of SOLs with no additional context is an overlap of other requirements/obligations set on the TO/GOs in other standards.

Likes 0	
Dislikes 0	

Response

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

Comment

Texas RE recommends the SDT consider the following:

- In Requirement R4, add "adjacent Reliability Coordinators Areas **within its Interconnection** or" unless it has an understanding that there is a need to confirm stability limits used in operations between RCs in different Interconnections.
- Revise Part 5.4 from "each established stability limit or each IROL" to "each established stability limit **and** each IROL applicable to the impacted Transmission Operator". Both the stability limit and the IROL should be provided to each impacted Transmission Operator.
- In Requirement R6, the term "System steady-state voltage limits" is not defined. Is this term intended to be different than the proposed term "System Voltage Limit," which was introduced in this project?
- Include a check and balance for use of the less limiting parameter in Requirement R6. This requirement allows for any criteria to be used (i.e. less limiting Facility Rating, etc) as it simply states a "technical rationale" has to be provided to any entity affected by a "less limiting" parameter.
- Requirement R6 uses "affected Transmission Planner, Transmission Operator and Reliability Coordinator," while R7 references "impacted Transmission Operator and Reliability Coordinator" and R8 references "impacted Transmission Owner and Generation Owner." Unless there is a specific reason for difference in verbiage, Texas RE recommends being consistent to avoid confusion and potential interpretation attempts at differences in language in the Requirements.
- Requirement R7 appears to exclude any CAP for Cascading or uncontrolled separation. Please provide the rationale for the exclusion.
- Provide more clarity in Requirement R8. In the phrase "any Facilities critical to the instability, Cascading or uncontrolled separation identified," it is not clear what would constitute "Facilities critical to the instability, Cascading or uncontrolled separation identified," and how these are different than "Facilities that comprise the Contingency(ies) (planning events only)."
- Requirement R8 requires the PC and TP to communicate "Facilities that comprise the Contingency(ies) (planning events only) and any Facilities critical to the instability, Cascading or uncontrolled separation identified." Many of the updated Standards (e.g. CIP-014-3, FAC-003-5) use the applicability language "Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System for planning events". It would be helpful if the information provided by the PC and TP directly maps to the applicability section of these other Standards. Texas RE recommends requiring that communication to the TO and GO include "Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System for planning events" instead of "Facilities that comprise the Contingency(ies) (planning events only) and any Facilities critical to the instability, Cascading or uncontrolled separation identified."
- Requirement R8 uses the phrase "planning events only." Texas RE recommends including an explanation that these events refer to the events in Table 1 of TPL-001.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
The time horizon in R6-R8 are currently identified as “Long-Term Planning Horizon” While this aligns with the horizon of the TPL-001-4 standard where issues would be identified, it is specifically the Near-Term Planning horizon that these issues point to. We recommend adjusting the time horizon assocoaited with R6-R8 to more accurately reflect the portion of the TPL-001-4 assessment they are intended to align to.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
None	
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 Regional Standards Committee	
Answer	
Document Name	
Comment	
NERC Standard IRO-17 obligates each Planning Coordinator and Transmission Planner to provide its Planning Assessment to impacted Reliability Coordinators. NERC TPL-001 includes the obligation that when the analysis indicates the inability of the system to meet the performance requirements. We believe FAC-014-3 R7 basically includes/requires the same if not similar information. If this additional detail is required, we suggest that IRO-017 be updated so that this type of request is located in a single requirement or standard.	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
NV Energy would like to communicate its additional concern over FAC-014-3, with the retirement of FAC-010-3. With the retirement of FAC-10-3, Transmission Planners will not be able to use their IROL methodology for the Planning Horizon anymore, and as stated, will be forced to adjust to their respective RC's SOL Methodology and definition of an IROL. NV Energy's concern with using a respective RC's IROL definition is the potential for the RC to identify an IROL for a more conservative loss than what a Transmission Planner would determine. NV Energy understands the need for a secure BES with the establishment of an IROL in an Interconnection; however, the ramifications of an IROL declaration stretch into multiple Standards that require a substantial amount of work for compliance implementation (i.e. CIP Standard suite), as well as the equipment modifications for facilities to monitor the flows on Elements within an IROL. NV Energy still believes their should still be a responsibility of defining IROLs with the Transmission Planner.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	
Document Name	
Comment	

No Comment

Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group

Answer	
Document Name	

Comment

The SPP Standards Review Group offers the following "***non-content***" considerations for SDT review:

1. Implementation of the "blue box" concept, as in previous standards development processes, which could give industry insight on proposed revisions.

2. Consideration of the concept could assist in a seamless transfer of information to the future Guideline and Technical Basis documentation.

Likes 0	
Dislikes 0	
Response	

Gul Khan - Oncor Electric Delivery - 1 - Texas RE

Answer	
Document Name	

Comment

n/a

Likes 0	
Dislikes 0	
Response	

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	
Document Name	

Comment	
The IRC SRC would like to note that discrepancies may be introduced when applying Facility Ratings derived in accordance with the RC's SOL methodology to the Near Term Transmission Planning Horizon because system topology may change from the time the Facility Ratings are developed in the current year to the time when the limit is applied in the Planning Assessment of the Near Term Transmission Planning Horizon; a study of anticipated system performance one (1) to five (5) years in the future. Therefore, it is preferable to retain the process under TPL-001-4 "as is."	
Likes 0	
Dislikes 0	
Response	

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
MISO supports the comments filed by the IRC SRC. The IRC SRC would like to note that discrepancies may be introduced when applying Facility Ratings derived in accordance with the RC's SOL methodology to the Near Term Transmission Planning Horizon because system topology may change from the time the Facility Ratings are developed in the current year to the time when the limit is applied in the Planning Assessment of the Near Term Transmission Planning Horizon; a study of anticipated system performance one (1) to five (5) years in the future. Therefore, it is preferable to retain the process under TPL-001-4 "as is."	
Likes 0	
Dislikes 0	
Response	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

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

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Jamie Johnson - California ISO - 2

Answer	
Document Name	

Comment

In addtion to comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee the CAISO has the following comments:

The SDT proposal to retire FAC-010 and the requirement to establish SOLs and IROLs for the planning horizon appear to be the result of the following two misconceptions:

- The “new” TPL 001-4 standard eliminates the need for developing SOLs and IROLs for the planning horizon, which is incorrect and
- SOLs are not useful for the reliable planning of the BES, which is also incorrect.

TPL 001-4 standard does not replace the need for developing SOLs and IROLs for the planning horizon and eliminate the need for the existing FAC-010 and Requirement R3 and R4 of the existing FAC-014. This is because TPL-001-4 is all about ensuring reliable service to firm load and firm transmission services. It does not require planning entities to stress tranfers on any part of the system to determine its limit. Also, since TPL-001-4 studies do not require stressing the system they are less suited to identifiying contingencies the lead to system instability, cascading and uncontrolled separation compared to SOL and IROL Studies performed under FAC-014 R3 and R4. Even if, TPL 001-4 studies identify contingencies that lead to such adverse impacts, they would be mitigated, which means there would be no planning contingencies with such adverse impacts.

SOLs are useful in the reliable planning of the system. For example, in the Western Interconnection (accepted) path ratings, which California ISO deems to be SOLs and are typically developed in the planning horizon, are used in the reliable planning of the system. In all its studies including the annual reliability assessment and local capacity studies, the CAISO ensures these SOLs are not exceeded. For example, reliability assessments and local capacity studies performed use this SOL information.

Likes 0	
Dislikes 0	

Response

Wayne Guttormson - SaskPower - 1

Answer	
Document Name	
Comment	
Support the MRO-NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
Please see comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	
No. Thank you	
Likes 0	
Dislikes 0	
Response	
Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey	
Answer	
Document Name	

Comment	
PG&E has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Marco Rios - Pacific Gas and Electric Company - 1	
Answer	
Document Name	
Comment	
PG&E has no additional comments.	
Likes 0	
Dislikes 0	
Response	

6. If you have any other comments regarding TOP-001-6 or IRO-008-3 that you haven't already provided, please provide them here.

Marco Rios - Pacific Gas and Electric Company - 1	
Answer	
Document Name	
Comment	
PG&E has no additional comments.	
Likes 0	
Dislikes 0	
Response	

Jack Stamper - Clark Public Utilities - 3	
Answer	
Document Name	
Comment	
These standards appear to be fine. One general comment on various FAC standards is the use of the term "impacted." It is used as a non-capitalized term however, how is an entity supposed to determine if another entity is impacted or not? If Clark is suposed to do something or say something to an impacted RC, what criteria is it to use to determine whether RC West is just an RC or an impacted RC?	
Likes 0	
Dislikes 0	
Response	

Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey	
Answer	
Document Name	
Comment	
PG&E has no additional comments.	

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	
Document Name	

Comment

No. Thank you.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment

Please see comments submitted by Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Wayne Guttormson - SaskPower - 1

Answer	
Document Name	

Comment

Support the MRO-NSRF comments.

Likes 0	
Dislikes 0	

Response

Jamie Johnson - California ISO - 2	
Answer	
Document Name	
Comment	
California ISO agrees with comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT suggests the implementation period be extended from 12 to 24 months in order to allow sufficient time to make necessary system changes.	
Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	

MISO supports the comments filed by the IRC SRC.

The IRC SRC respectfully requests the SDT extend the timeframe for implementation from 12 to at least 24 calendar months to support the changes needed to comly with FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3. Some entities will need to enhance existing tools to accurately track, validate and reconcile SOL exceedances; particularly in those instances where the Reliability Coordinator (RC) is not also the Transmisison Operator (TOP). In addition to tools, implementation of the new standards will require collaboration between the RC and its respective TOPs to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. Additionally, a 24-month implementation timeframe would provide the time needed to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production, particularly in light of the ongoing operational challenges associated with the COVID-19 pandemic and the anticipated demand this will place on EMS vendors as entities compete for limited resources. For these reasons, the IRC SRC is requesting the SDT consider extending the implementation timeframe to at least 24 months.

Likes 0	
Dislikes 0	
Response	

Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	
Document Name	
Comment	

n/a

Likes 0	
Dislikes 0	
Response	

Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	
Document Name	
Comment	

IPL offers no further comment.

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
NV Energy agrees with the requirement language provided for TOP-001-6 R14, but has concerns with the language provided for the measures for R14. NV Energy has concerns with the phrase “successfully mitigated”, and it not being appropriate, even if it is just for suggested evidence. Requirement R14 states only to show a Plan that was initiated to mitigate SOLs, not to prove mitigation. While success is obviously the desired outcome, it is not the only possible outcome, and this language addition to the measures for R14 seems to extend beyond the intent of the requirement.	
Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	

None

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE has the following comments for proposed IRO-008-3:

- In Requirement R1, revise Interconnection Operating Reliability Limits to Interconnection Reliability Operating Limits.
- In Requirement R5, "exceedance" is added after SOL but is not in Requirement R6. It was added in the VSL/VRF matrix for Requirement 5 and parts of Requirement R6. Requirement R6 VSL/VRF only has "exceedance" added within the first statement and not the second statements (after the "OR" in Lower, Moderate, and High VSL columns on page 12 of 15). Since the language appears to be so similar, Texas RE recommends consistency in where exceedance is added.
- Requirement R7, as well as the measure, capitalizes "Real-time Monitoring." Real-time Monitoring is not a defined term in the NERC Glossary and monitoring should not be capitalized.
- Texas RE noticed the Data Retention section does not include Requirement R7. Texas RE recommends Requirement R7's data retention match Measures M1 - M3, Measure M5, and Measure M6 at a minimum.
- Texas RE noticed the Guidelines and Technical Basis has been removed from this standard, but it is still in place for other standards, such as PRC-026. Texas RE recommends following the Technical Rationale Transition Plan and determine whether the Guidelines and Technical Basis is Technical Rationale or Implementation Guidance.

- Texas RE recommends the IRO-008-3 mapping document include the BA since it is included in the standard.
- Texas RE has the following comments for proposed TOP-001-6:
- The term “Real-Time System Operators” is used in several places in the rationale document. Since it is not a defined term in NERC Glossary, Texas RE recommends using the term System Operator, which is defined.
- In Requirement R15, it is unclear as to whether the phrase “in accordance with its Reliability Coordinator’s SOL methodology” is referring to the “exceeded” SOL or the need to “inform”. The VSL/VRF matrix language structure places the phrase after “inform”. Texas RE recommends reviewing the sentence and make clarifying changes as necessary.
- Requirement R25, as well as the measure, capitalizes “Real-time Monitoring”. Real-time Monitoring is not a defined term in the NERC Glossary and monitoring should not be capitalized. It is also capitalized in the VSL/VRF matrix and the Evidence Retention sections of the standard.
- Texas RE requests justification for revising the Evidence Retention requirement for Requirement R14. This justification for the change could be captured in the mapping document for TOP-001-6.
- The mapping document appears to contain guidance on how to comply with TOP-001-6, in the statement “communication could range from simply RC and TOP sharing via ICCP output from the real time monitoring and RTCA output”. This is not a method to inform the RC of “actions taken”. ICCP reflects results of actions but does not necessarily reflect the action(s) actually taken. The mapping document is not an appropriate place for putting guidance on how to comply with the standard and the process for developing Implementation Guidance can be utilized if the SDT would like to provide guidance on complying with the standard.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer	
Document Name	

Comment

Need to add the word "its" to the modified portion of Requirement R6.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum.

Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	2015-09_Unofficial_Comment_Form_202006 - SOCO Comments Final.pdf
Comment	
Detailed comments are in the attached file with special formatting for clarity and emphasis where needed (strike-through, highlighting, etc.).	
Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	
Document Name	
Comment	
MEC Supports NSRF Comments	

Likes 0	
Dislikes 0	

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer	
Document Name	

Comment

Considering that "Consistent with SOL methodology" is mentioned throughout the Standard, suggest referencing "SOL expectations outlined in FAC-011-3" somewhere within the Standard.

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	
Document Name	

Comment

MEC supports MRO NSRF comments.

RO-008 R5. What is the purpose of the Reliability Coordinator notifying the Transmission Operator of SOL exceedances? If it's for the Transmission Operator's Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive this information from its Reliability Coordinator based on its individual operating environment. To keep this requirement detached in IRO-008 is contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements and remove redundancies. If not used for the Transmission Operator's Real-time monitoring and Real-time assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

IRO-008 R6. What is the purpose of the Reliability Coordinator notifying the Transmission Operator when SOL exceedances are prevented or mitigated? If it's for the Transmission Operator's Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive information from its Reliability Coordinator. To keep this requirement detached in IRO-008 is contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements and remove redundancies. If not used for the Transmission Operator's Real-time monitoring and Real-time assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

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

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

"These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments".

IRO-008 R5. What is the purpose of the Reliability Coordinator notifying the Transmission Operator of SOL exceedances? If it's for the Transmission Operator's Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive this information from its Reliability Coordinator based on its individual operating environment. To keep this requirement detached in IRO-008 is contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements and remove redundancies. If not used for the Transmission Operator's Real-time monitoring and Real-time assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

IRO-008 R6. What is the purpose of the Reliability Coordinator notifying the Transmission Operator when SOL exceedances are prevented or mitigated? If it's for the Transmission Operator's Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive information from its Reliability Coordinator. To keep this requirement detached in IRO-008 is contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements and remove redundancies. If not used for the Transmission Operator's Real-time monitoring and Real-time assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

Likes 0	
Dislikes 0	
Response	

Bruce Reimer - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	

The changes to these standards place a considerable reporting requirement on SOL

exceedance. Manitoba Hydro is requesting 30 month implementation period rather than, normal

12 months implementation period to work out SOL reporting methodology with the RC.

Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.	
Likes 0	
Dislikes 0	
Response	

Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	
Document Name	
Comment	
Why R25 couldn't have just been incorporated into R14? R25 basically stating a TOP has to use its RC's methodology, which indirectly implies it has to be in each TOP operating plan for the identified SOL exceedances for R14?	
Likes 0	
Dislikes 0	
Response	

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

John Allen - City Utilities of Springfield, Missouri - 4	
Answer	

Document Name	
Comment	

IRO-008 R5. What is the purpose of the Reliability Coordinator notifying the Transmission Operator of SOL/IROL exceedances? If it's for the Transmission Operator's Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive this information from its Reliability Coordinator based on its individual operating environment. To keep this requirement detached in IRO-008 is not effective or efficient and contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements, reduce administrative burdens and remove redundancies. If not used for the Transmission Operator's Real-time monitoring and Real-time assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

IRO-008 R6. What is the purpose of the Reliability Coordinator notifying the Transmission Operator when SOL/IROL exceedances are prevented or mitigated? If it's for the Transmission Operator's Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive information from its Reliability Coordinator. To keep this requirement detached in IRO-008 is contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements, reduce administrative burdens and remove redundancies. If not used for the Transmission Operator's Real-time monitoring and Real-time assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

Likes 0	
Dislikes 0	
Response	

7. With the retirement of FAC-010, and the elimination of Planning-based SOLs and IROLs, do you agree with the changes to CIP-014, FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026?

John Allen - City Utilities of Springfield, Missouri - 4	
Answer	No
Document Name	
Comment	

The standards need to be results-based and define *a clear and measurable expected outcome* for all Registered Entities. By adding "*that adversely impact the reliability of the Bulk Electric System*" implies that some instability, Cascading or uncontrolled separation is acceptable. Who determines that threshold? The Reliability Coordinator in its SOL methodology? How do we ensure a consistent expectation and application for all Registered Entities?

Likes 0	
Dislikes 0	
Response	

Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	No
Document Name	
Comment	

Regarding the changes to CIP-014, Seattle City Light has five areas of concern. The first three relate to revised Section 4.1.1.3 and the fourth and fifth address impacts to existing R1.

First, the changes to Section 4.1.1.3 to replace the reference to IROL Facilities identified by an entity's Reliability Coordinator, Planning Coordinator, or Transmission Planner with Facilities associated with instability, Cascading, or uncontrolled separation, that also adversely impact BES reliability for planning events, is inconsistent with Criteria 2.6 of CIP-002 Attachment 1, from which Section 4.1.1.3 was taken. The applicability CIP-014 is designed to conform to the criteria of CIP-002 for Medium impact Transmission Facilities. For consistency among the CIP Standards, Seattle suggests that CIP-002 Attachment 1, Criteria 2.6, also be changed along with CIP-014.

Second, the changes to Section 4.1.1.3 are confusing and perhaps redundant. As proposed, the criteria to identify applicable Facilities has two components: (i) loss that creates instability, Cascading, or uncontrolled separation, (ii) that adversely impacts BES reliability for planning events. So far as Seattle is aware, nowhere else in the NERC Standards are the "big three" bad events (instability, Cascading, uncontrolled separation) qualified in this way; they are presumed by their existence to create adverse BES impacts. In addition, the language "adverse impact for planning events" adds another layer of confusion. What is an adverse impact for a planning event? Considerable effort has been spent by NERC and industry over the years to qualify "adverse BES impact" for CIP-002, yet this new language introduces a different new concept that expands adverse impact to new territory. Additional clarity is required. As a simpler solution, Seattle suggests that the qualifier phrase "that adversely impacts…" be dropped from the proposed change to Section 4.1.1.3.

Third, the changes to Section 4.1.1.3 add a new burden on entities that was not previously present. For IROLs, there exist established processes to inform entities of the existence of IROLs and document those Facilities critical to their derivation. The "IROL Cards" and IROL website used in the Western Interconnection are examples of these processes. As a result, it is easy for entities to apply existing Section 4.1.1.3 criteria (as well as those of CIP-002 Criteria 2.6) and crystal clear to document conclusions at audit. For the proposed changes, there is no established mechanism or consistent process for Planning Coordinators or Transmission Planners to share with entities information about Facilities related to BES instability, Cascading, or uncontrolled separation, nor is there established language about how to identify such Facilities. Presumably such information is shared in some fashion as a matter of good practice, but absent any established means to do so and consistent approach to documentation, the change creates a new burden on entities to track down such information from others and to clarify findings in unequivocal, crystal clear language to satisfy any auditor. As a solution, Seattle suggests that somewhere in the body of changes introduced by Project 2015-09, there be a new requirement for Planning Coordinators and Transmission Planners to inform subject entities, in a standardized manner, of Facilities related to to BES instability, Cascading, or uncontrolled separation.

Fourth, the changes to Section 4.1.1.3 cause redundancy for CIP-014 R1. Specifically, R1 requires a transmission planning study to identify Facilities associated with instability, Cascading, or uncontrolled separation. These are the identical criteria that cause a Facility to be applicable in 4.1.1.3. As proposed, the requirement would require a transmission study on Facilities identified to be associated with instability, Cascading, or uncontrolled separation to determine if they are associated with instability, Cascading, or uncontrolled separation. Ridiculous! As a possible solution, Seattle suggests CIP-014 R1 be rewritten to exempt from evaluation any Facility meeting Section 4.1.1.3 (because it already has been so evaluated), and revise R2 to require a third party evaluation of the entity's R1 study and the Section 4.1.1.3 evaluation of the applicable Planning Coordinator/Transmission Planner.

Fifth, the different qualifiers used in Section 4.1.1.3 and R1 create unnecessary confusion. Section 4.1.1.3 qualifies applicability based on "adversely impacting the reliability of the BES reliability for planning events" whereas R1 qualifies applicability "within an Interconnection." It is not clear how these different qualifiers impact identified instances of identified instability, Cascading, or uncontrolled separation. There's enough confusion and auditor dissent for CIP-014 about how to apply the "within an Interconnection" qualifier; no new confusion is needed. As suggested above, Seattle recommends that the Section 4.1.1.3 "adverse impact" qualifier be removed, which would also address R1 confusion as discussed here. If qualifying language is desired, Seattle recommends that the same language be used in Section 4.1.1.3 and R1.

Likes 0	
Dislikes 0	

Response

Bruce Reimer - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

We agree with the retirement of planning based IROLs. We also agree with the

changes made to the CIP-014 and PRC-023 standards. However we don't agree with the use of a

general statement to say that the retirement of FAC-10 will eliminate all planning based SOLs.

Planing coordinator can still use their SOLs with valid technical rationale.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	
Comment	

"These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments".

The MRO NSRF agrees with the changes to FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026 (subject to the recommendations made in questions 1 to 6), but disagrees with changes to CIP-014 at this time.

CIP-014 Applicability Section 4.1.1.3 comes from CIP-002-5.1a Medium Impact Rating criterion 2.6. The SDT for Project 2016-02 considered and rejected this proposed change for CIP-002-6, which just passed industry ballot without any change to criteria 2.6 and 2.9, both of which continue to reference IROLs, a NERC Glossary-defined term.

The proposal would lower the threshold from Interconnection instability to any instability affecting the BES, representing a potentially substantial increase in scope for CIP-014, and sundering the connection to and synergy with CIP-002, creating disparate populations.

Deference should be given to the SDT for Project 2016-02 with respect to any conforming changes to CIP-002 and CIP-014, which need to be addressed concurrently and consistently.

The MRO-NSRF suggests the SDT coordinate with Project 2018-03 which shows FAC-013 and TOP-001 R22 scheduled to be retired by FERC.

Likes 0	
Dislikes 0	
Response	

Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System

Answer	No
Document Name	
Comment	

LES supports comments provided by the MRO NSRF related to CIP-014.

Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

AEP continues to have concerns regarding 4.2.2, Transmission Facilities, within FAC-003. Proposing new requirements in FAC-014 to ensure a Transmission Planner is performing a "planning assessment" does not automatically ensure such efforts will naturally flow to FAC-003 simply because they are in the same standard family. The SDT may be making some assumptions regarding communication in that regard. It should not be assumed that communication between a Transmission Planning function and a Transmission Owner (a Forestry department, for example) would be a naturally occurring activity. If these changes are indeed pursued, the SDT will need to give consideration on how to ensure this communication is taking place. It should also be noted however that while more insight is needed on ensuring this communication takes place, care should also be taken to ensure no restrictions or limitations be unnecessarily placed on the parties involved.

These proposed revisions could unintentionally lead to a line not being properly identified. Any planning event causing instability that is identified in planning assessments, whether the contingency is above or below 200 kV, would have a corrective action plan which may possibly include generation redispatch. If generation redispatch is applied in the operation time-frame, as might be assumed in planning, there is no instability for a planning event and no lines will be identified. We are not certain whether or not the SDT realizes this could be applicable to CAPs of any nature. Could the SDT provide insight as to whether these proposed revisions are requiring that the identification of lines below 200 kV take place pre-CAP or instead post-CAP? In any event, we disagree with the proposed revisions, which we believe changes from identifying lines in a practical way, to doing so in a less practical manner using planning studies.

As stated in the previous comment period, we believe additional text is needed here to ensure no lines are unintentionally excluded by a) the timing of their being identified as part of an IROL and b) the timing of any facilities identified, which could lead to instability, Cascading, or uncontrolled separation within associated planning assessments. The SDT's response from the previous comment period gives the impression that they may possibly be unaware of the guidance provided in the original Errata which was eventually incorporated into the GTB. The team provided an example of a line identified as an IROL and then incorporated into FAC-003 and that "it could be months or years before the vegetation management caught up with the designation, providing no practical benefit." The SDT may wish to further review the GTB of this standard to ensure they are aware such guidance has already been provided in this standard regarding how soon after a line is identified that it becomes incorporated into the vegetation management program. With this in mind, AEP once again recommends that this section be clarified in the following manner… *"Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation* ***<u>or overhead transmission line operated below 200kV that have been established as part of an IROL by the Reliability Coordinator per IRO-014-3 R1.</u>****"*

Proposed Implementation Plan: The changes proposed are very expansive and involve many individuals across a number of Functional Entities. In addition, new cross-functional procedures and processes would need to developed and established to meet the proposed obligations. As a result, we believe 36 months would be more appropriate.

We believe the references to planning events in CIP-14 Applicability Section 4.1.1.3 and FAC-003 Applicability Sections 4.2.2 and 4.3.1.2 could be more clearly stated. We recommend that CIP-014 Applicability Section 4.1.1.3 be revised to state "Transmission Facilities at a single station or substation location that are identified by the Planning Coordinator, or Transmission Planner, per its Planning Assessment of the NearTerm Transmission Planning Horizon as Facilities that if lost or degraded *due to planning events* are expected to result in instances of instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System."

AEP would like to make a suggestion and encouragement regarding how the standards drafting team provides redlined documents for industry review. While redlined documents using the previously proposed revision as a baseline do provide a very beneficial way for the reader to identify only the most-recently proposed changes, we believe that they cannot be the only redlined document provided during these comment and balloting periods. These particular redlines are simply a "delta" between the current and previous draft revision and do NOT show all the proposed additions and deletions that have been retained-to-date. This could result in the reader misunderstanding or misinterpreting the content in the draft. For example, text shown in black could be a) text currently included in the version under enforcement or b) new text that was proposed in a previous comment period but "no longer considered new text" in the current comment period. In addition, text shown as deleted could be a) text that has been newly proposed for deletion in the current comment period or b) text that was proposed for addition in a previous comment period draft but then later struck from consideration in a latter comment period. As a result, when multiple revisions are proposed over time, the reader would have to review each and every draft proposed to date and somehow determine for themselves all the changes retained to date. A balloter is not voting on only the most recently proposed changes, they are voting on all the proposed changes that have been retained-to-date. As a result, we recommend drafts showing only most recent changes also be accompanied by an additional redlined document which shows *all the proposed revisions retained to date*, and using the version under enforcement as a baseline.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

BC Hydro agrees with the changes to CIP-014, FAC-003, FAC-013 and PRC-023. However, on FAC-013, PRC-023 and PRC-026, BC Hydro offers the following comments and suggestions.

FAC-013-3 Project 2018-03 Standards Efficiency Review Retirements drafting team recommended the retirement of FAC-013-2. As stated in their June 7, 2019 petition to FERC, NERC determined that the standard is not needed for BES reliability, and should therefore be retired. BC Hydro suggest that a revision of FAC-013-2 is no longer warranted.

PRC-023-5 Through the inclusion of the Transmission Planner (TP) in Attachment B, Criterion B2, the proposed revision indicates TP's responsibilities of selecting the circuits subject to requirements R1 through R5. BC Hydro recommends that the TP functional entity be included in the Applicability section of the standard and the TP's responsibilities clarified in the language of the requirement.

PRC-026-2 Requirement 1 mandates that the Planning Coordinator (PC) use Near-Term Planning Assessment results to identify stability constraints associated BES elements. However, the Near-Term Planning Assessment would be conducted by Transmission Planners (TPs) and coordinated by their PC. If a TP fails to provide its PC the list of stability related BES elements, PC could be held non-compliant to PRC-026-2. The proposed draft does not identify the Transmission Planners (TPs) as a responsible entity. BC Hydro recommends that the Transmission Planner's role to timely provide its PC with the BES Elements meeting R1 criteria be reflected within the requirement, and TP functional entity be added to the Applicability section of the standard.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
MEC supports MRO NSRF comments. The MRO NSRF agrees with the changes to FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026 (subject to the recommendations made in questions 1 to 6), but disagrees with changes to CIP-014 at this time. CIP-014 Applicability Section 4.1.1.3 comes from CIP-002-5.1a Medium Impact Rating criterion 2.6. The SDT for Project 2016-02 considered and rejected this proposed change for CIP-002-6, which just passed industry ballot without any change to criteria 2.6 and 2.9, both of which continue to reference IROLs, a NERC Glossary-defined term. The proposal would lower the threshold from Interconnection instability to any instability affecting the BES, representing a potentially substantial increase in scope for CIP-014, and sundering the connection to and synergy with CIP-002, creating disparate populations. Deference should be given to the SDT for Project 2016-02 with respect to any conforming changes to CIP-002 and CIP-014, which need to be addressed concurrently and consistently. The MRO-NSRF suggests the SDT coordinate with Project 2018-03 which shows FAC-013 and TOP-001 R22 scheduled to be retired by FERC.	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	No

Document Name	
Comment	

ReliabilityFirst offers the following comments for consideration.

1. PRC-026-2

   i. The revised Standard uses the capitalized term “Near-Term Planning Horizon,” but this term is not in the NERC Glossary. The term defined in the NERC Glossary is “Near-Term **Transmission** Planning Horizon.”

   ii. The revised Standard uses the capitalized term “Near-Term Planning Horizon” but this term is not in the NERC Glossary.

2. PRC-023-5

   i. Attachment B criteria B2 added the term in bold: “… instances of instability, Cascading, or uncontrolled separation, **that adversely impact the reliability of the Bulk Electric System** for planning events.” The bolded term is also used in FAC-011-4, and our comments are nearly the same: What is the meaning of “that adversely impact the reliability of the Bulk Electric System?” Is it possible for instability, Cascading, or uncontrolled separation to NOT adversely impact the reliability of the BES? What is the criteria for determining if instability, Cascading, or uncontrolled separation do or do not adversely impact the reliability of the BES? Attachment B criteria B2 is open to interpretation, and therefore does not promote the reliability of the BES. Note that the NERC approved definition of IROL also uses the term “… that adversely impact the reliability of the Bulk Electric System.”

   ii. There are references in R6 to version 4 of the Standard (PRC-023-4) that should be changed to reference the new PRC-023-5 Standard

   iii. Recommend update to the new format with the measurements placed under each requirement.

3. FAC-003-5

   i. While RF disagrees with the removal of IROL lines as a whole due to reduction of lines falling under the compliance standards regarding maintenance, the noted red-lined changes are recommended for approval as stated.

4. CIP-014-3

   i. For all these, references to planning events needs to be more clearly stated as being the planning events in TPL-001 Table 1.

CIP-014-03 R4.1.1.3 **This needs to be made clearer. I am reading this revision in several different ways, none of which I believe to be then intent of the change. I think the reference to planning events needs to be changed to single station or single station location event.**

Here are the two ways that I read the standard as proposed.

1) What are the planning events? Are they the subset of TPL-001 Table 1 P1 through P7 events that could cause the loss of the single station or substation location, or all facilities at a single voltage level in a station or substation? If so, the CIP standard should provide more detail on what assumptions must be made for the planning events, that differ from the same events when studied per TPL requirements.

2) Are the planning events additional contingencies after system adjustments, and with the single station or substation still out of service? If so, this is a significant change the severity of events that this standard addresses. Is this a requirement to study the station outage concurrent with a planning event?

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Dominion has the same concerns with the term instability that we have previously shared both here and in regards to prvious versions of CIP-002. The current use of the term, without clarification that it is intended to be applied to wide area issues, could lead to misinterpretation of the intent and lead to inconsistent application of the standard.

Likes 0	
Dislikes 0	

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC

Answer	No
Document Name	

Comment

BHE does not agree with the changes to CIP-014

BHE agrees with the changes to FAC-013

BHE agrees with the changes to PRC-002

BHE agrees with the changes to PRC-023

BHE agrees with the changes to PRC-026

BHE agrees with EEI's response to this question. The EEI response conveys that the proposed changes to the CIP-014 Aplicability Section would break the alignment between CIP-014 and CIP-002.

Likes 0	

Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	No
Document Name	
Comment	
Some changes seem to be minor and some require revisiting the methodology and more coordination. Unless there is a fatal flaw with the existing, the proposed changes create a more complicated process that impacts several Standards.	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No
Document Name	
Comment	
OGE has similar concerns expressed by MRO-NSRF on CIP-014 changes. The proposed CIP-014 change would lower the threshold from Interconnection instability to any instability affecting the BES, representing a potentially substantial increase in scope for CIP-014. OGE recommends the SDT to ensure any changes made to CIP-014 conforms with CIP-002.	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MEC Supports NSRF Comments	

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

FirstEnergy disagrees with the proposed changes to CIP-014 as the changes proposed are not also being applied to NERC Reliability Standard CIP-002 - Attachment 1, criteria 2.6. The four (4) sub-parts of Applicability Section 4.1.1 in the current approved CIP-014 standard are based on a subset of the NERC CIP-002 Attachment 1 criteria. The proposed change to CIP-014 section 4.1.1.3 would bring inconsistency with the CIP-002 - Attachment 1, criteria 2. While we do not necessarily oppose the proposed revision, the SDT should also ensure the change is made to CIP-002 for consistency and the proposed changes would need to be more carefully considered for impact within the CIP-002 standard before we can fully support.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum.

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

ATC Supports the comments of the MRO NSFR and EEI.

CIP-014 Applicability Section 4.1.1.3 comes from CIP-002-5.1a Medium Impact Rating criterion 2.6. The SDT for Project 2016-02 considered and rejected this proposed change for CIP-002-6, which just passed industry ballot without any change to criteria 2.6 and 2.9, both of which continue to reference IROLs, a NERC Glossary-defined term.

The proposal would lower the threshold from Interconnection instability to any instability affecting the BES, representing a potentially substantial increase in scope for CIP-014, and sundering the connection to and synergy with CIP-002, creating disparate populations.

Deference should be given to the SDT for Project 2016-02 with respect to any conforming changes to CIP-002 and CIP-014, which need to be addressed concurrently and consistently.

Likes 0	
Dislikes 0	

Response

Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter

Answer	No
Document Name	

Comment

Oncor supports the comments submitted by EEI for CIP-014.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment

PacifiCorp does not agree with the changes to CIP-014 and supports EEI and MRO NSRF with their comments. The CIP-014 Applicability Section 4.1.1.3 comes from language in CIP-002-5.1a Medium Impact Rating criterion 2.6. The SDT for Project 2016-02 filed CIP-002-6 with FERC for approval, which passed industry ballot without any change to criteria 2.6 and 2.9, both of which continue to reference IROLs, a NERC Glossary-defined term.

The proposal would lower the threshold from Interconnection instability to any instability affecting the BES, representing a potentially substantial increase in scope for CIP-014, and changing the connection and synergy with CIP-002.

Deference should be given to the SDT for Project 2016-02 with respect to any conforming changes to CIP-002 and CIP-014, which need to be addressed concurrently and consistently.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE is concerned with removing the Reliability Coordinator (RC) in the applicability of proposed CIP-014-3. The RC, as specified in the proposed FAC-014 standard, establishes Interconnection Reliability Operating Limits (IROLs) in accordance with its SOL methodology. Once identified in the operational horizon, however, the RC will likely adopt more conservative operational criteria to avoid instability, Cascading or uncontrolled separation. As Texas RE reads the current FAC-014 requirements, the Planning Coordinator (PC) and Transmission Planner (TP) will be required to plan using at least these more conservative Facility Rating, voltage limits, and stability criteria. The use of these more conservative limits in the Planning Assessment could potentially make it less likely that the TP and PC will ultimately identify instability, Cascading, or uncontrolled separations that adversely impact the reliability of the Bulk Electric System. As such, facilities currently subject to the CIP-014 requirements today would be potentially excluded from the scope of the proposed CIP-014.

Texas RE understands that the SDT's intent in revising the CIP-014 was not to change the substantive scope of the CIP-014 requirements. To ensure there is no inadvertent changes to the facilities subject to CIP-014, Texas RE recommends that facilities identified by the RC as causing instability, Cascading, or uncontrolled separations that adversely impact the reliability of the Bulk Electric System be retained in the scope of the CIP-014 requirements.

Texas RE has the following comments regarding proposed FAC-003-5:

- It is unclear how planning events that involve multiple elements (e.g. TPL-001-4 P6 event) would fall into the applicability of FAC-003-5. The applicability section of FAC-003-4 made it clear using the language of "Each overhead transmission line operated below 200kV identified as an element of an IROL…" FAC-003-5, however, simply uses the language "a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event." It is not clear whether each element that comprises the planning event or only a single line "that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System".
- The asterisk on Table 2 appears to be inconsistent with FAC-014. The asterisk is applicable only "if PC has determined such per FAC-014." FAC-014 includes both of the PC and TP in Requirements R6-R8. The footnote as written excludes the TP so it is unclear whether TP

Facilities, determined per FAC-014 R8, are subject to vegetation management. This could leave a gap in the reliable operations of the grid if the list of Facilities derived by the PC and TP are different. Texas RE recommends adding “and TP” to the footnote in FAC-003-5.

Texas RE noticed that the rationale for PRC-002-3 includes a reference to PRC-002-2 in Requirement R6. The Guidelines and Technical Basis Section also contain references to PRC-002-2 (e.g. Introduction Section, Guideline for Requirement R6, R7).

Texas RE has the following comments for proposed PRC-023-5.

Texas RE recommends Transmission Planner be added to Requirement R6 and the Applicability section of the standard. In section 4.2 Circuits, there are references to the lines selected by the Planning Coordinator in accordance with Requirement R6. Requirement R6, with the Planning Coordinator as the only functional entity type listed, references Attachment B of PRC-023-4. Attachment B contains an addition in B2 regarding the Transmission Planner selection of a circuit. As stated in the “Criteria” section of Attachment B: “If any of the following criteria apply to a circuit, applicable entity must comply with the standard”. If Transmission Planner is not included, there could be a gap in the reliable operations of the grid if the list of circuits selected by the Planning Coordinator and Transmission Planner are different.

- Requirement R6 contains references to PRC-023-4 Attachment B (and Measurement M6 has similar reference.), which needs to be updated to PRC-023-5.

Texas RE has the following comments for proposed PRC-026-2.

- Texas RE requests the SDT consider capitalizing Transmission Line in Section A 4.2, Requirement R1, and Part 2.2 since it is a defined term.
- Texas RE requests the SDT to provide more clarification regarding the term “planning event”. Texas RE recommends stating that the planning events refer to Table 1 in TPL-001. As written, registered entities could make their own definition of what a “planning event” is and that definition may not cover all TPL-001 events listed in Table1.

Texas RE has the following comments for the White Paper.

Texas RE inquires as to which definitions are being proposed. The white paper contains a revised definition of System Operating Limit. There is also a definition of System Voltage Limit posted for a different project phase. Texas RE recommends putting the definitions in the implementation plan so it is clear what is being proposed.

- Please ensure consistency with the standards with regards to capitalizing NERC Glossary Terms. For example, “Steady State” is capitalized and it is not a NERC Glossary term.
- On Page 3, there is nothing after i. Part 6.1.3
- “Real-time Monitoring” is capitalized in bullet 5 on page 5, bullet 2 of page 7, and bullet 6 of page 7. Real-time monitoring is not a defined term in the NERC Glossary and should not be capitalized.
- On page 4, Texas RE recommends using the language of the standard to describe the intent of the SOL concept within FAC-011. Texas RE recommends revising number 1. to “Facility Ratings, System Voltage Limits, and the stability performance criteria noted in R4”.

- criteria noted in R4".
- On page 6 there is a discussion about maintaining SOL performance that includes a reference to "associated time parameters" for System Voltage Limits. As discussed previously, there is no time requirement stated within the definition of System Voltage Limits and therefore clarity is needed to implement the standards using System Voltage Limit and referencing a time duration.
- On page 6, Texas RE recommends revising "unit stability" to "angular stability" to match the Standard.
- On page 6, "Stability" should not be capitalized in the last sentence as it is not defined in the NERC Glossary. "Stability" is capitalized in the discussion about Voltage Stability Limits as well.
- Number 3 on page 6 references TOP-001-3. Since this project is proposing TOP-001-6, Texas RE recommends revising it to TOP-001-6.

Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

A common language has been utilized to revise these standards stating "that adversely impact the reliability of the BES". This language does not detail what is considered "adverse impact," and therefor introduces inconsistencies among the industry.

Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	

Comments: AZPS supports the changes made to FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026 but do not support the changes made to CIP-014.

AZPS supports EEI's comments that changes made to CIP-014 are not necessary and these changes could have unintended consequences for the industry. Similar changes were proposed under Project 2016-02 and industry rejected the changes in 2018. At that time, EEI offered the following comments to the Project 2016-02 SDT:

The use of the term 'instability', within the context of Criterion 2.6, represents a potential point of confusion, because it could be interpreted as increasing the scope for CIP-002-6. While the term 'instability' is broadly understood and used in the definition of many terms defined within the NERC Glossary of Terms, it has been limited in scope to specific reliability impacts to the Bulk Electric Systems. However, the proposed language in Criterion 2.6 does not impose similar limits and could be interpreted to mean entities need to reclassify many cyber assets to medium impact. Additionally, BES generator reclassified under the medium impact criteria that also have a Control Center within the physical boundaries of that facility would now become a high impact BES Cyber Assets.

In order to remedy this concern, EEI suggests that the SDT consider language similar to what is currently used in the GTB for Criterion 2.9 which ties the term "instability" to Wide Area impacts. This would be consistent, in approach, with the scope of CIP-014 by limits the scope of instability to a defined area of impact.

Ultimately the Project 2016-02 SDT reverted to the original language. Additionally, the concern expressed by the Industry back in 2018 for CIP-002 remains unchanged. For this reason, we ask the SDT to not break the linkage between CIP-014 part 4.1.1.3 (Applicability Section) and CIP-002-5.1a (Attachment 1, Criterion 2.6) creating unnecessary confusion.

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 Regional Standards Committee

Answer	No
Document Name	

Comment

Please consider not revising CIP-014, at this time. The revision of CIP-014 applicability section 4.1.1.3 will be inconsistent with CIP-002 Attachment 1 – Impact Rating Criteria 2.6. This could lead to uncertainty regarding applicability and impact ratings. We suggest that CIP-014 and CIP-002 should be revised at the same time.

Likes 0	
Dislikes 0	

Response

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC supports the comments as submitted by EEI.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

PRC-002 - TVA disagrees with the proposal to change responsibility for PRC-002-3 R5 from the Planning Coordinator (PC) to the Reliability Coordinator (RC). We believe the responsibility for determining the need for DDR equipment should remain with the PC as this is better evaluated in the near-term planning horizon.

FAC-003 - On page 9, we recommend adding "…for a planning event" to the Category 1A description for consistency with the edits made for Category 1B, 2A, 2B, 4A and 4B.

CIP-014 - We agree with comments provided by several other entities regarding the proposed change to applicability section 4.1.1.3 creating a misalignment with CIP-002 - Attachment 1, part 2.6.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 1, 5, 3, 6; Bryan Taggart, Westar Energy, 1, 5, 3, 6; Derek Brown, Westar Energy, 1, 5, 3, 6; Grant Wilkerson, Westar Energy, 1, 5, 3, 6; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., ; James McBee, Westar Energy, 1, 5, 3, 6; Marcus Moor, Westar Energy, 1, 5, 3, 6; - Douglas Webb, Group Name Westar-KCPL

Answer	No
Document Name	

Comment

The Evergy companies support, and incorporate by reference, Edison Electric Institute's response to Question No. 7.

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	

Comment

NV Energys supports the following comments provided by EEI:

EEI supports the changes made to FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026 but do not support the changes made to CIP-014. Similar changes were proposed under Project 2016-02 and the industry rejected those changes in 2018. At that time, EEI offered the following comments to the Project 2016-02 SDT:

The use of the term 'instability', within the context of Criterion 2.6, represents a potential point of confusion, because it could be interpreted as increasing the scope for CIP-002-6. While the term 'instability' is broadly understood and used in the definition of many terms defined within the NERC Glossary of Terms, it has been limited in scope to specific reliability impacts to the Bulk Electric Systems. However, the proposed language in Criterion 2.6 does not impose similar limits and could be interpreted to mean entities need to reclassify many cyber assets to medium impact. Additionally, BES generator reclassified under the medium impact criteria that also have a Control Center within the physical boundaries of that facility would now become a high impact BES Cyber Assets.

In order to remedy this concern, EEI suggests that the SDT consider language similar to what is currently used in the GTB for Criterion 2.9 which ties the term "instability" to Wide Area impacts. This would be consistent, in approach, with the scope of CIP-014 by limits the scope of instability to a defined area of impact.

Ultimately the Project 2016-02 SDT reverted to the original language. Additionally, the concern expressed by the Industry in 2018 for CIP-002 remains unchanged. The linkage between CIP-014 part 4.1.1.3 (Applicability Section) and CIP-002-5.1a (Attachment 1, Criterion 2.6) should remain to avoid confusion.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1	
Answer	No
Document Name	

Comment

On behalf of Exelon, Segments 1, 3, 5, & 6

Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	

Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	No
Document Name	
Comment	
Please consider not revising CIP-014, at this time. The revision of CIP-014 applicability section 4.1.1.3 will be inconsistent with CIP-002 Attachment 1 – Impact Rating Criteria 2.6. This could lead to uncertainty regarding applicability and impact ratings. We suggest that CIP-014 and CIP-002 should be revised at the same time.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI supports the changes made to FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026 but do not support the changes made to CIP-014. Similar changes were proposed under Project 2016-02 and the industry rejected those changes in 2018. At that time, EEI offered the following comments to the Project 2016-02 SDT: The use of the term 'instability', within the context of Criterion 2.6, represents a potential point of confusion, because it could be interpreted as increasing the scope for CIP-002-6. While the term 'instability' is broadly understood and used in the definition of many terms defined within the NERC Glossary of Terms, it has been limited in scope to specific reliability impacts to the Bulk Electric Systems. However, the proposed language in Criterion 2.6 does not impose similar limits and could be interpreted to mean entities need to reclassify many cyber assets to medium impact. Additionally, BES generator reclassified under the medium impact criteria that also have a Control Center within the physical boundaries of that facility would now become a high impact BES Cyber Assets. In order to remedy this concern, EEI suggests that the SDT consider language similar to what is currently used in the GTB for Criterion 2.9 which ties the term "instability" to Wide Area impacts. This would be consistent, in approach, with the scope of CIP-014 by limits the scope of instability to a defined area of impact. Ultimately the Project 2016-02 SDT reverted to the original language. Additionally, the concern expressed by the Industry in 2018 for CIP-002 remains unchanged. The linkage between CIP-014 part 4.1.1.3 (Applicability Section) and CIP-002-5.1a (Attachment 1, Criterion 2.6) should remain to avoid confusion.	
Likes 0	
Dislikes 0	
Response	

Michael Jones - National Grid USA - 1	
Answer	No
Document Name	
Comment	

The changes made to the Applicability Section of CIP-014 no longer align with CIP-002. We also note that the proposed changes to PRC-023-3 and PRC-026-2 referring to Planning Assessments no longer correspond to the language in PRC-002-3 which does not refer to Planning Assessments but refer to BES Elements that are part of an Interconnection Reliability Operating Limit (IROL) [Requirement R5, Part 5.1.4 as well as in the Guidelines and Technical Basis Section, Guideline for Requirement R5].

The use of the term 'instability' in CIP-014-3 represents a potential point of confusion. While the term 'instability' is broadly understood and used in the definition of many terms defined within the NERC Glossary of Terms, while it is used in TPL-001-5.1 in the context of identifying "System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding" as defined and documented by each Transmission Planner and Planning Coordinator within their Planning Assessment.

There are also (minor) inconsistencies in the wording referring to identifying Facilities per Planning Assessment of the Near-Term Transmission Planning Horizon as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, e.g., "planning events" in CIP-014-3 and PRC-023-3 vs. "a planning event" in FAC-003-5 and PRC-026-2 as well as variations in the wording related to the above reference to results from Planning Assessments in the sub-bullets of Requirement R1 of PRC-026-2. Please consider using consistent wording.

In addition, please consider an alternate approach for revising the Applicability criterion in Part 4.1.1.3 of CIP-014-3 such as: "Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies." This is essentially the same criterion as in CIP-014-2 without including the Planning Coordinator or Transmission Planner functional entities.

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

Southern Company does not support adjusting the applicable entity in PRC 002 [R5] from TP/PC to RC for the Eastern Interconnect. TP/PCs are appropriately positioned to identify where dynamic Disturbance recording (DDR) data is required based upon their wide area view of reliability needs, particularly as it pertains to changing system conditions that can be best gauged in the near term planning horizon. Furthermore, this time horizon is more aptly suited for determining equipment installation requirements due to the lead-time associated with the installation of any BES equipment. Lastly, there are potentially significant implementation plan and timing concerns with shifting the applicability of existing requirements to another functional entity, that could correspondingly shift the location and amount of DDR coverage required. These implementation considerations would need to be addressed.

Likes 1	Mark Pratt, N/A, Pratt Mark
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

For each of these standards, the intent of this project was to replace the term IROL with the definition of an IROL. In doing this, the SDT also added Transmission Planner to the requirements. In the original standards, the requirements were for the Planning Coordinator to identify the IROL. This work was assigned to the Planning Coordinators as they have a global view of the interconnected transmission systems. While Transmission Planners do perform stability studies, it is the Planning Coordinators that have this overarching view of the interconnecting systems when they perform their studies, thus it should remain only the responsibility of the Planning Coordinator to identify those facilities that are the basis for these standards in stability violations equivalent to an IROL.

ITC requests the SDT clarify the term Planning event with additional clarifying information. If the intent was for the contingencies to include the P0-P7 Planning event, clarify by using this terminology or be very explicit to identify that extreme events are not included. This clarification is requested in PRC-023 and PRC-026.

Likes 0	
Dislikes 0	

Response

Lee Maurer - Oncor Electric Delivery - 1

Answer	No
Document Name	

Comment

Oncor supports EEI comments.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

A common language has been utilized to revise these standards stating "that adversely impact the reliability of the BES". This language does not detail what is considered "adverse impact," and therefor introduces inconsistencies among the industry.

Likes 0	
Dislikes 0	

Response

Wayne Guttormson - SaskPower - 1

Answer	No
Document Name	

Comment

Support the MRO-NSRF comments.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

Please see comments submitted by Edison Electric Institute

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	No

Document Name	
Comment	

WAPA endorses the MRO-NSRF comments regarding the Implementation Plan being too short for the necessary adjustments and training.

as for the rest:

WAPA does not agree with the use of "degraded" in FAC-003-5 or CIP-014-3. Degraded is a concept pertinent to BES Cyber Systems, BES Cyber Assets, Protection System, or RAS meaning that normal functionality is compromised. The term makes sense in the context of Cyber Assets given that their capabilities or availability can be reduced, e.g., slower sample rate of telemetry for protection, loss of high speed communication-aided fault clearing but Zone 2 backup remains intact, induced misoperations or failures to operate, etc. In the context of the establishment of Facility Ratings (FAC-008-3 Requirement R6), degradation is not a consideration. In other words, Facility Ratings are established consistent with a Facility Ratings methodology (FAC-008-3 Requirements R2 and R3) that may typically use normal or expected System configuration as a precondition for determining the Equipment Ratings, of which there is serially-connected most-limiting equipment, that comprise the Facility. Transmission line Normal and Emergency Facility Ratings should already consider ampacity, sag, and conductor temperature rise over ambient, amongst many parameters, when established.

The concept of transmission or generation Facility degradation is difficult to describe because the degraded System state or configuration is ambiguous. Degraded could refer to a myriad of abnormal System states, including: n-X prior outages, flows immediately post-Contingency, congestion requiring market redispatch, off-nominal System inertia due to displacement of conventional spinning mass generation with renewables, etc. Transmission Owners and Generator Owners do not publish reams of Facility Ratings considering every possible degraded state, nor would it be achievable for operating entities to use this information. In fact, take the simple example of Dynamic Line Ratings or Ambient Adjusted Ratings. Firstly, only a minority of North American transmission lines are currently operated with temperature-adjusted Facility Ratings. And, in most cases Transmission Planners and Planning Coordinators employ static Facility Ratings for the purposes of steady-state assessments, only invoking any consideration of temperature adjustment after identifying post-Contingency failures to meet System performance requirements of TPL-001-4 (soon -5) Table 1.

It is a fundamental Facility Ratings concept, reinforced by the Glossary of Terms definition, that Emergency Ratings have an associated duration. Therefore, WAPA disagrees with any approach to a calculated post-Contingency exceedance of a Normal Facility Rating that does not give some consideration of the duration the exceedance may persist before mitigation. Frankly, with the interest in reliability in mind, the SDT should not want to imply Transmission Planners and Planning Coordinators ignoring the headspace between Normal and Emergency Facility Ratings by only considering exceedances of Emergency Facility Ratings appropriate for Corrective Action Plans. To do so would be to plan the transmission system such that Normal Facility Ratings were irrelevant and essentially to state that all Normal Facility Ratings exceedances will be mitigated in the Operations Horizon; which we know to be poor planning and not always possible.

WAPA disagrees that the draft FAC-003-5 Applicability, Part 4.2.2 that infers flexibility that allows the Planning Coordinator or Transmission Planner to judiciously identify "a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event." On the contrary, this is a prescriptive inclusion that obligates the Planning Coordinator or Transmission Planner to perform unique analysis in addition to the requirements of TPL-001-4 (and -5). WAPA hopes that the SDT will remember that TPL-001-4 (and -5) Requirement R2, Part 2.7 requires the Planning Assessment to include Corrective Action Plan(s) addressing how failures to meet System performance requirements will be met; it does not require the Planning Coordinator or Transmission Planner to identify degraded Facilities that may be expected to result in instability, Cascading, or uncontrolled separation.

While annual Planning Assessment practices vary, instances of instability, Cascading, or uncontrolled separation that maybe mitigated by allowable Table 1 Interruption of Firm Transmission Service and/or Non-Consequential Load Loss will likely have no Corrective Action Plan developed and, thus, would not be reported as part of an annual Planning Assessment. WAPA has concerns that the “expected to result in instances of instability, Cascading, or uncontrolled separation” draft language is vague enough to imply that typical annual Planning Assessments that document Corrective Action Plans for instability, Cascading, or uncontrolled separation that are failures to meet System performance requirements of Table 1 will become insufficient. The result, we foresee, is that Transmission Planners and Planning Coordinators will become obligated to document every instance of instability, Cascading, or uncontrolled separation that they observe during analysis supporting their annual Planning Assessment, not just those instances that required Corrective Action Plans.

To summarize our comments:

The use of “degraded” Facilities is vague and should be removed from all proposed instances from FAC-003-5 and CIP-014-3.

The use of “adversely impacts the reliability of the Bulk Electric System” is redundant and should be removed from all proposed instances from PRC-023-5, CIP-014-3, FAC-011-4, and FAC-014-3.

WAPA greatly appreciates the time and attention that the SDT has made to each of the Reliability Standards affected by the “raising of the bar” for SOLs. Your work is necessary and relevant! Thank you for the opportunity to provide comment.

Likes 0	
Dislikes 0	

Response

Marco Rios - Pacific Gas and Electric Company - 1

Answer	No
Document Name	

Comment

The Standard Drafting Team should review the proposed changes and fully consider all implications of changes to other standards. Below PG&E identifies a few instances that should be further investigated and considered as part of this project:

- The changes to CIP-014 are concerning with this Project. Section 4.1.1.1 (all facilities 500 kV or higher) and Section 4.1.1.2 (weighting criteria comparable to other CIP standards) previously worked together with Section 4.1.1.3, which served as an exception to include additional facilities determined to be “critical to the derivation of” IROLs in the CIP-014 studies. Now, the language has removed the engineering judgment and requires ALL facilities from the Near-Term TP Assessment meeting the “instability, Cascading, and uncontrolled separation” language to be included in the CIP-014 studies, without any judgment applied. The language in 4.1.1.3 must be enhanced to ensure that only outages with severe system impacts.

- PRC-023 Attachment B Criterion B2, in which the TP has now been added to the PC as another entity that can designate possible facilities to be evaluated for Transmission Relay Loadability. However, the PC is required to perform an assessment in R6 of this standard to determine a required circuit list, but the TP has no such requirement. There are no other details provided to the TP describing how a such selection would/should occur and be communicated to the PC, which could lead to issues with compliance.
- The proposed changes to FAC-003, does not clearly state that Section 4.2.2 (each overhead transmission line operated below 200kV identified as an element of an IROL under FAC-014 by PC) applies to non-WECC utilities. Conversely, PG&E would be subject to Section 4.2.3 (each overhead transmission line operated below 200kV identified as an element of a Major WECC Transfer Path in the BES by WECC) which is clearly applicable to PG&E. It would also be useful to remove the strike-through text in M6 listed below:
    - o "Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records."

The reason for this recommendation is that the current language can be confusing and provides no value. The months leading up to and following the beginning and end of a calendar year (i.e. December and January) fall outside of the growing season. Moving to an 18 month window regardless of calendar vastly simplifies the requirement for both the Utility Company and the Regulator.

- In PRC-026 R1 the PC has reporting requirements to the TO and GO which have been updated as part of this effort. How do these requirements mesh with FAC-014-3 R8, since there appears to be some overlap in the requirements? Does it make sense to continue to have these similar reporting requirements in separate standards?

It appears that some of proposed changes to these standards could use additional scrutiny to ensure that there are no unintended consequences of these changes.

Likes 0	
Dislikes 0	

Response

Truong Le - Truong Le On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 5, 3; Chris Gowder, Florida Municipal Power Agency, 6, 4, 5, 3; Dale Ray, Florida Municipal Power Agency, 6, 4, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 5, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Truong Le

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment	

Conndiditionally Yes - Request clarification of the phrase “adversely impacts” for impacted Standards. For example, the first FAC-003 instance reads: 4.3.1.2 Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that "adversely impacts" the reliability of the Bulk Electric System for a planning event… Please confirm the phrase “adversely impacts” has the exact meaning as the NERC Reliability Standards Glossary defined phrase “Adverse Reliability Impact”; if different, please define phrase "adversely impacts".

Additionally, due to the numerous methodologies, procedures, processes, tools, and training impacts associated with this Project, suggest extending implementation period from 12 months to 30 months.

Likes 0	
Dislikes 0	
Response	

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer	Yes
Document Name	
Comment	

PPL NERC Registered Affiliates support the proposed revisions to FAC-003. However, the revised language is somewhat ambiguous, and we would appreciate the Drafting Team providing clarification on how the revisions apply to lines under 200kV described in 4.2.2. The conditions described in the revised FAC-003 affecting lines under 200 kV would not occur without being in violation of planning requirements of TPL-001-5 and TPL-001-4, which require looking to the future and mitigating where a single outage may result in a stability issue.

Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	

With regards to standards revisions or deletions to FAC-010-3, FAC-011-3, and FAC-014-2 requirements for determining and communicating SOLs used in the reliable planning and operation of the BES, BPA agrees with the associated changes to FAC-003, FAC-013, PRC-002, PRC-023, and PRC-026.

Regarding CIP-014-3, it is unclear how the Planning Assessment performed by the Planning Coordinator or the Transmission Planner in Applicability criteria 4.1.1.3 relates to the risk assessment performed by the Transmission Owner in Standard Requirement R1.

BPA suggests the following edits to criteria 4.1.1.3 to help clarify.

4.1.1.3. “Transmission Facilities that are identified by the Planning Coordinator or Transmission Planner through its Annual Planning Assessment of the Near-Term Transmission Planning Horizon, at a single station or substation location that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System for planning events.”	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
In our opinion CIP-014 part 4.1.1.3 (Applicability Section) and CIP-002-5.1a (Attachment 1, Criterion 2.6) should remain to avoid confusion.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Hydro-Québec Production agrees with the changes to PRC-002. We are not impacted by the other standards.	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
IPL offers no further comment.	

Likes 0	
Dislikes 0	

Response

Gul Khan - Oncor Electric Delivery - 1 - Texas RE

Answer	Yes
Document Name	

Comment

Oncor supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Jamie Johnson - California ISO - 2

Answer	Yes
Document Name	

Comment

In addtion to comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee the CAISO has the following comments:

Requirement R6 and 6.1 of the draft PRC-023-5 continue to reference PRC-023-4 Attachment B. Wondering if that's intentional or an oversight which should reflect version 5 instead of 4 of PRC-023? Additionally, the Implementation Plan still references PRC-023-4 instead of PRC-023-5 and should be reviewed due to a spelling error of "its" on page 4 following *conduct* and prior to *first assessment* that should be corrected.

Likes 0	
Dislikes 0	

Response

Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey

Answer	Yes
Document Name	

Comment

The Standard Drafting Team should review the proposed changes and fully consider all implications of changes to other standards. Below PG&E identifies a few instances that should be furthe investigated and consideed as part of this project:

- For example, the changes to CIP-014 are concerning with this Project. Section 4.1.1.1 (all facilities 500 kV or higher) and Section 4.1.1.2 (weighting criteria comparable to other CIP standards) previously worked together with Section 4.1.1.3, which served as an exception to include additional facilities determined to be "critical to the derivation of" IROLs in the CIP-014 studies. Now, the language has removed the engineering judgment and requires ALL facilities from the Near-Term TP Assessment meeting the "instability, Cascading, and uncontrolled separation" language to be included in the CIP-014 studies, without any judgment applied. The language in 4.1.1.3 must be enhanced to ensure that only outages with severe system impacts.

- Another example is PRC-023 Attachment B Criterion B2, in which the TP has now been added to the PC as another entity that can designate possible facilities to be evaluated for Transmission Relay Loadability. However, the PC is required to perform an assessment in R6 of this standard to determine a required circuit list, but the TP has no such requirement. There are no other details provided to the TP describing how a such selection would/should occur and be communicated to the PC, which could lead to issues with compliance.

- The proposed changes to FAC-003, does not clearly state that Section 4.2.2 (each overhead transmission line operated below 200kV identified as an element of an IROL under FAC-014 by PC) applies to non-WECC utilities. Conversely, PG&E would be subject to Section 4.2.3 (each overhead transmission line operated below 200kV identified as an element of a Major WECC Transfer Path in the BES by WECC) which is clearly applicable to PG&E. It would also be useful to remove the strike-through text in M6 listed below:

"Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records."

- The reason for this recommendation is that the current language can be confusing and provides no value. The months leading up to and following the beginning and end of a calendar year (i.e. December and January) fall outside of the growing season. Moving to an 18-month window regardless of calendar vastly simplifies the requirement for both the Utility Company and the Regulator.

- In PRC-026 R1 the PC has reporting requirements to the TO and GO which have been updated as part of this effort. How do these requirements mesh with FAC-014-3 R8, since there appears to be some overlap in the requirements? Does it make sense to continue to have these similar reporting requirements in separate standards?

It appears that some of proposed changes to these standards could use additional scrutiny to ensure that there are no unintended consequences of these changes.

Likes 0	
Dislikes 0	

Response

Maurice Paulk - Cleco Corporation - 1,3,5,6

Answer	Yes
Document Name	

Comment

See SEE, EEI and MISO comments

Likes 0	
Dislikes 0	

Response

Michael Courchesne - Michael Courchesne On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Michael Courchesne

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Hirchak - Cleco Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Glen Allegranza, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ray Jasicki - Xcel Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	

NO.

NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.

Additionally, NERC has a SER project. Project 2015-09, Establish and Communicate, System Operating Limits, proposals create more redunancies; counter to the purpose of the SER project.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 1, 5, 3; - Amy Casuscelli	
Answer	
Document Name	
Comment	
Xcel Energy recommends a longer implementation plan due to the coordination and potential tools required.	
Likes 0	
Dislikes 0	
Response	
Mickey Bellard - Seminole Electric Cooperative, Inc. - 1,5 - SERC	
Answer	
Document Name	CIP-014 SBS Comments 8-3-2020.docx
Comment	
Likes 0	
Dislikes 0	
Response	