NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project Name:	Project 2015-09 Establish and Communicate System Operating Limits | FAC-014-3 and Implementation Plan
Comment Period Start Date:	10/23/2020
Comment Period End Date:	12/7/2020
Associated Ballots:	2015-09 Establish and Communicate System Operating Limits FAC-014-3 AB 4 ST 2015-09 Establish and Communicate System Operating Limits Implementation Plan AB 4 OT

There were 60 sets of responses, including comments from approximately 139 different people from approximately 107 companies representing 10 of the Industry Segments as shown in the table on the following pages.

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

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President of Engineering and Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. Do you agree with the 24-month Implementation Plan?

2. The SDT acted on industry comments and revised FAC-014-3 by adding requirement R5.6 and revising measure M3 and requirement R8. Do you agree with the revisions?

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

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
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
New York Independent	Gregory Campoli	2		ISO/RTO Standards	Gregory Campoli	NYISO	2	NPCC

System Operator				Review Committee	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
					Nick Fogleman	Prairie Power Incorporated	1,3	SERC

					Susan Sosbe	Wabash Valley Power Association	3	RF
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Kylee Kropp	Sunflower Electric Power Corporation	1	MRO
					David Hartman	Arizona Electric Power Cooperative	1	WECC
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
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC

					William Shultz	Southern Company Generation	5	SERC
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
Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
Vijay Puran	NYSPS	6	NPCC
ALAN ADAMSON	New York State Reliability Council	10	NPCC
Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
Brian Robinson	Utility Services	5	NPCC
Quintin Lee	Eversource Energy	1	NPCC
Jim Grant	NYISO	2	NPCC

					John Pearson	ISONE	2	NPCC
					John Hastings	National Grid USA	1	NPCC
					Michael Jones	National Grid USA	1	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 RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Yasser Bahbaz	Southwest Power Pool Inc.	2	MRO
					Charles Cates	Southwest Power Pool Inc.	2	MRO

1. Do you agree with the 24-month Implementation Plan?	
Michael Whitney - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
See prior NCPA and John Allen City Utilities prior balloting comments.	
Likes 1	Truong Le, N/A, Le Truong
Dislikes 0	
Response	
Thank you for your comment.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
See prior NCPA and John Allen City Utilities prior balloting comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Thomas Foltz - AEP - 5	

Answer	No
Document Name	
Comment	
While we do appreciate the Standards Drafting Team's proposal of the 24-month rather than the originally proposed 12-month Implementation Plan, we still believe 36 months would be more appropriate. As stated previously, the proposed changes 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. Once again, we believe 36 months would be more appropriate.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. We have consulted numerous industry stakeholders, which resulted in the revised proposal for a 24-month Implementation Plan. Since a large portion of the respondents has suggested this timeframe may be lengthy enough to accomplish implementation, the SDT will suggest a 24-month plan in the final posting.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
While AEPC appreciates the SDT's proposal of 24-months rather than the initial proposal of a 12-month Implementation Plan, AEPC believes a 36-month timeframe would be more appropriate as the proposed changes are time intensive to implement. AEPC also signed on to ACES comments.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. We have consulted numerous industry stakeholders, which resulted in the revised proposal for a 24-month Implementation Plan. Since a large portion of the respondents has suggested this timeframe may be lengthy enough to accomplish implementation, the SDT will suggest a 24-month plan in the final posting.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
We endorse the comments provided by AEP on 11/24/2020.	
Likes 1	Truong Le, N/A, Le Truong
Dislikes 0	
Response	
Thank you for your comments. We have consulted numerous industry stakeholders, which resulted in the revised proposal for a 24-month Implementation Plan. Since a large portion of the respondents has suggested this timeframe may be lengthy enough to accomplish implementation, the SDT will suggest a 24-month plan in the final posting.	
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	
While ACES appreciates the SDT's proposal of 24-months rather than the initial proposal of a 12-month Implementation Plan, ACES believes a 36-month timeframe would be more appropriate as the proposed changes are time intensive to implement.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. We have consulted numerous industry stakeholders, which resulted in the revised proposal for a 24-month Implementation Plan. Since a large portion of the respondents has suggested this timeframe may be lengthy enough to accomplish implementation, the SDT will suggest a 24-month plan in the final posting.	
Glen Allegranza - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
no comments	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
AZPS supports the change from 12-months to the 24-month implementation plan.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Jerry Horner - Basin Electric Power Cooperative - 6	
Answer	Yes
Document Name	
Comment	
Basin Electric supports the MRO NSRF comments. Jerry Horner	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The MRO NERC Standards Review Forum (MRO NSRF) supports the changes made by the SDT to extend the Implementation Plan from 12 to 24 months.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
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 the changes made by the SDT to extend the Implementation Plan from 12 to 24 months.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jamie Johnson - California ISO - 2	
Answer	Yes

Document Name	
Comment	
CAISO agrees with comments submitted by the ISO/RTO Council (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
MISO supports comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC) and MRO NERC Standards Review Forum (MRO NSRF).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter	
Answer	Yes
Document Name	
Comment	

Yes, Oncor agrees with the 24-month Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Entergy supports MISO's comments.	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports the proposed 24-month Implementation Plan.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the proposed 24-month Implementation Plan. Submitted on behalf of Exelon: Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
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 extend the Implementation Plan from 12 to 24 months.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Douglas Webb - Evergy - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Evergy incorporates by reference and supports the comments of Edison Electric Institute (EEI) in response to Question 1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI commnets	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	

Answer	Yes
Document Name	
Comment	
EEI supports the proposed 24-month Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Robert Hirchak - Cleco Corporation - 6	
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	

Richard Brooks - Reliable Energy Analytics LLC - 8	
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	
Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kjersti Drott - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nurul Abser - NB Power Corporation - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
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	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
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	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Ellis - Pacific Gas and Electric Company - 3 - WECC	
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	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
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	

Richard Jackson - U.S. Bureau of Reclamation - 1	
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 erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Pamalet Mackey - Pamalet Mackey On Behalf of: Ed Hanson, 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	
Likes 0	
Dislikes 0	
Response	

Karen Weaver - Tallahassee Electric (City of Tallahassee, FL) - 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	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jose Avendano Mora - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ed Hanson - Pacific Gas and Electric Company - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Neil Shockey - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.

2. The SDT acted on industry comments and revised FAC-014-3 by adding requirement R5.6 and revising measure M3 and requirement R8. Do you agree with the revisions?

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

ERCOT appreciates the Standard Drafting Team's revisions to FAC-014-3, Requirement R8, in response to the last round of comments. However, ERCOT believes Requirement R8 should be further clarified in order to remove an ambiguity that exists in the current draft.

In Requirement R8, the word "impacted" is ambiguous (impacted by what?) because the requirement also refers to "instability, Cascading or uncontrolled separation." As written, the requirement can be interpreted as implying an impact to virtually everything in a particular interconnection. It is unclear whether Requirement R8 is intended to mean that only the owners of the facilities that comprise the planning event contingency(ies) that cause "instability," as identified in the near-term planning assessment, need to be notified that certain specific facilities they own are part of a planning event contingency that would cause "instability." If this is the correct interpretation, which ERCOT believes to be the case, ERCOT suggests Requirement R8 provide as follows in order to remove the ambiguity:

R8. Each Planning Coordinator and each Transmission Planner shall annually provide each Transmission Owner and Generation Owner that owns Facilities that are part of one or more planning event Contingencyies that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES, as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon, a list of the Transmission Owner's or Generation Owner's Facilities that are part of each planning event Contingency that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES. [Violation Risk Factor: Medium] [Time Horizon: Long- term Planning]

Alternatively, confirmation from NERC in the form of guidance accompanying FAC-014-3 may be helpful in clarifying the scope of Requirement R8. ERCOT further notes that it intends to vote in favor of a revised FAC-014-3, provided the scope of Requirement R8 is further clarified.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT is considering clarifications in the rationale for Requirement R8 to ensure the intent of the requirement is clear. The term “impacted” is used several times in the SDT-proposed version of FAC-014 in R5 and R7 as well. The use of this term in R8 is consistent with those other instances in that a measure of specificity was needed in the determination of the subset of TO and GO entities to send information to. The term was thus included to clarify that only the TO and GO with identified facilities would be included in the communication from the PC & TP. This term was added to the text of R8, in part, as a response to comments to previous postings where commenters brought up the concern that the prior wording of R8 could be interpreted as including all TO and GO entities regardless of whether their Facilities were identified by the PC or TP.	
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	

If the application of Part 5.6 is intended to include three latter time horizons (Operations Planning, Same-day Operations and Real-Time Operations), ACES believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard. A common language has been utilized to revise R8 which includes the language: “that adversely impact the reliability of the BES”. This language does not detail what is considered “adverse impact,” and therefore introduces inconsistencies among the industry.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The proposed Requirement R5, Part 5.6 is in response to a FERC directive (Order 777) to include a communication path for IROL information to the owning entities as part of this project. It was addressed as a subpart of R5 which addresses RC communication requirements of SOLs (including IROLs).	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy is supporting MRO NSRF comments: **FAC-014-3, Part 5.6** The MRO NSRF notes that FAC-014, Part 5.6 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Reliability Coordinators provide Transmission Owners and Generator Owners with a list of their Facilities identified as critical to the derivation of an IROL and its associated contingencies. If the application of Part 5.6 is intended to include: Operations Planning, ***Same-day***	

Operations and Real-Time Operations (with emphasis on the latter time horizons), the MRO NSRF believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard.

If, however, the intent is to limit the time horizon to Operations Planning as indicated in Parts 5.1, 5.2 and 5.4 (tied to Part 5.2), which are limited in their application to “at least once every 12 months,” FAC-014 may be the best fit location. If this is the case, the MRO NSRF recommends Part 5.6 be clarified to “at least once every 12 months” and Same-day Operations and Real-Time Operations be stricken from th applicable Time Horizons for Requirement R5 as illustrated below:

R5. Each Reliability Coordinator shall provide: [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months.

Finally, if the deriviation of an IROL and its associated critical contingencies is considered temporary, there is no language in Part 5.6 of the standard that limits when and if CIP-002-5.1a must be applied to these facilities. The MRO NSRF recommends the SDT address this as part of this project as this has the potential to trigger a new Medium Impact Rating for an entity.

Regardless of location, the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28).

FAC-014-3, Requirement 8

The MRO NSRF notes that FAC-014, R8 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Planning Coordinators and Transmission Planners provide Transmission Owners and Generator Owners with a list of their Facilities that comprise planning event Contingencies that would cause instability, Cascading or uncontrolled separation that adversely impact BES reliability as identified in its Planning Assessment. Similar to what is noted above for Part 5.6 , the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28).

Without this linkage, Generator Owners receiving information pursuant to FAC-014-3, Requirement 8 for the first time may fail to make the correlation to CIP-002-5.1a	
Likes 0	
Dislikes 0	
Response	
Refer to response to MRO NSRF comments	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP RTO	
Answer	No
Document Name	
Comment	
The Southwest Power Pool (SPP) Regional Transmission Organization (RTO) agrees the proposed language in requirement 5.6 plays a role in the reliability of the Bulk Electric System (BES), however, SPP RTO recommends the Reliability Coordinators (RCs) communication to the Transmission Owners (TOs) and Generation Owners (GOs) of facilities could be incorporated into an IRO Reliability Standard, possibly IRO-009, based on the contribution potential of the derivation of Interconnection Reliability Operating Limits (IROL's), and/or IRO-010 which contains actions for the RC to operate within IROLS and contain the requirements for the RC and asset owners to communicate information for IROLs. SPP RTO interrupts that the FAC Reliability Standards are intended for specifying what the RC needs to include in the methodology to calculate System Operating Limits (SOLs) and IROLs. In a requirement such as 5.6, the calculation for IROL could confuse the communication of the obligations of asset owners to the RC. SPP recommends the proposed modification of the 5.6 requirement language: The original language states "*identified as critical to the derivation of an IROL*" and SPP is proposing "*identified by the RC as critical to the derivation of an IROL*".	

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The proposed Requirement R5, Part 5.6 is in response to a FERC directive (Order 777) to include a communication path for IROL information to the owning entities as part of this project. It was addressed as a subpart of R5 which addresses RC communication requirements of SOLs (including IROLs).

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

Answer	No
Document Name	

Comment

FAC-014-3, Part 5.6

The IRC SRC notes that FAC-014, Part 5.6 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Reliability Coordinators provide Transmission Owners and Generator Owners with a list of their Facilities identified as critical to the derivation of an IROL and its associated contingencies. If the application of Part 5.6 is intended to include: Operations Planning, ***Same-day Operations and Real-Time Operations (with emphasis on the latter time horizons)***, the IRC SRC believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard.

If, however, the intent is to limit the time horizon to Operations Planning as indicated in Parts 5.1, 5.2 and 5.4 (tied to Part 5.2), which are limited in their application to "at least once every 12 months," FAC-014 may be an appropriate location. The latter being the case, the IRC SRC recommends the time horizon for Part 5.6 be clarified to "at least once every 12 months" and Same-day Operations and Real-Time Operations be stricken from the applicable Time Horizons for Requirement R5 as illustrated below:

R5. Each Reliability Coordinator shall provide: [Violation Risk Factor: High] [Time Horizon: Operations Planning]

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies ***at least once every twelve calendar months.***

Finally, if the derivation of an IROL and its associated critical contingencies is considered temporary, we ask for clarification whether these facilities become subject to requirements under CIP-002-5.1a. There is no language in Part 5.6 of the standard that limits when and if CIP-002-5.1a must be applied to these facilities. The IRC SRC asks the SDT exclude the ability of temporary IROLs from triggering CIP-002-5.1a, Attachment 1, Medium Impact Rating provisions. This could be accomplished by defining the time horizon for Criterion 2.6, similar to what has been done with Criterion 2.3; i.e. "as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

Regardless of location, the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28). Without this linkage, Generator Owners receiving information pursuant to FAC-014-3, Requirement 8 may fail to correlate this information with CIP-002-5.1a, particularly as FAC-014-3, measure M5 allows information to be provided via posting to a secure website. As FAC-014-3 is not directly applicable to Generator Owners (section 4), they may not even be aware that they would need to check their Reliability Coordinator's website for this posting and that they would need to check it on a daily basis should the Same-day Operations and Real-Time Operations time horizons for R5 be retained.

FAC-014-3, Requirement 8

The IRC SRC notes that FAC-014, R8 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Planning Coordinators and Transmission Planners provide Transmission Owners and Generator Owners with a list of their Facilities that comprise planning event Contingencies that would cause instability, Cascading or uncontrolled separation that adversely impact BES reliability as identified in its Planning Assessment. Similar to what is noted above for Part 5.6 , the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28). Without this linkage, Generator Owners receiving information pursuant to FAC0-014-3, Requirement 8 for the first time may fail to make the correlation to CIP-002-5.1a. Without this linkage, Generator Owners receiving information pursuant to FAC-014-3, Requirement 8 may fail to correlate this information with CIP-002-5.1a, particularly as FAC-014-3 is not directly applicable to Generator Owners.

FAC-014-3, Measurement 3

The byproduct of removing "in accordance with its Reliability Coordinator's SOL methodology" to align with Requirement 3 language, introduces an inconsistency with similar FAC-014-3 language around each of its other Requirements and Measures and which is not justified by the Rationale which effectively makes it an option to include or not include the language within an RC's SOL methodology.

Doing so effectively allows for a TOP to provide their SOLs to the RC in any timeframe of their choosing, so long as they are provided. While the SDT Rationale points to potential duplicity or alignment with that of IRO-010-2 and thus the need for flexibility through the removal of

"in accordance with its Reliability Coordinator's SOL methodology", IRO-010-2 makes no direct reference to System Operating Limits. As such, the IRC SRC believes "in accordance with its Reliability Coordinator's methodology" to be appended to both R3 and M3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The proposed Requirement R5, Part 5.6 is in response to a FERC directive (Order 777) to include a communication path for IROL information to the owning entities as part of this project. It was addressed as a subpart of R5, which addresses RC communication requirements of SOLs (including IROLs). Likewise, R8 is in response to the same FERC directive. It is important to note that, without the proposals in Requirement R5, Part 5.6 & R8, there is no requirement for this type of information to be sent to the appropriate owners. Therefore, this is a reliability enhancement as it relates to this communication. The SDT is also adding clarity to the appropriate time horizons in Requirement R5, Part 5.6 with an updated posting of the standard. The concern with temporary conditions that lead to IROL establishment is well taken and the SDT agrees that temporary IROL conditions are not the appropriate trigger for TO & GO consideration pursuant to CIP-002-5.1a. However, this ambiguity exists today due to the wording in criteria 2.6 of the CIP standard that references specific facilities, identified by the RC (or planning entities) that are critical to the derivation of an IROL. The proposed Requirement R5, Part 5.6 does not change this reality. The SDT is not currently pursuing changes to the CIP standard as these efforts failed in the past when combined with the efforts of an ongoing CIP SDT. It is this SDT's opinion that CIP modifications would be best served by another drafting team, with an appropriate SAR, that can address all issues with the current criteria, some of which are not related to Project 2015-09.	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	

1. Does this mean PC/TPs need to have “adverse impact” criteria in their Annual Assessment or does this return to the concept of any failure to meet TPL-001-4/5 System performance requirements of Table 1? As an alternative to all of this confusion, why not simply mirror the concept and clear language in Requirement R7:

   Requirement R8 - Each Planning Coordinator and each Transmission Planner shall annually communicate to each impacted Transmission Owner and Generation Owner a list of their Facilities identified as part of a Corrective Action Plan(s) developed to address any that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The wording referenced in the comment is pulling from the IROL definition and not the (similar) Adverse Reliability Impact definition. It is not clear what confusion the comment is referencing.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern Company agrees with the addition of requirement R5.6 as well as the revisions to measure M3.

While the revised wording in requirement R8 is an improvement to the the previous posting, Southern Company believes that this requirement could result in burdensome communication even if there isn’t any identified issues per the Planning Assessment to communicate. As such, Southern Company recommends the addition of the following sentence at the end of Requirement R8:

“Planning Coordinators and Transmission Planners that do not identify any Facilities are not required to perform the annual communication”.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. It is the opinion of the SDT that the current wording of R8 clearly specifies the specific Facilities that are applicable. Additional clarity is being added to the rationale as well.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
We endorse the comments provided by AEP on 11/24/2020.	
Likes 0	
Dislikes 0	
Response	
Refer to response to referenced comments.	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	No
Document Name	
Comment	
Entergy supports MISO's comments.	
Likes 0	

Dislikes 0	
Response	
Refer to response to referenced comments.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
MISO supports comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC) and MRO NERC Standards Review Forum (MRO NSRF).	
Likes 0	
Dislikes 0	
Response	
Refer to response to referenced comments.	
Jamie Johnson - California ISO - 2	
Answer	No
Document Name	
Comment	
CAISO agrees with comments submitted by the ISO/RTO Council (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	

Response	
Refer to response to referenced comments.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
If the application of Part 5.6 is intended to include three latter time horizons (Operations Planning, Same-day Operations and Real-Time Operations), AEPC believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard. A common language has been utilized to revise R8 which includes the language: “that adversely impact the reliability of the BES”. This language does not detail what is considered “adverse impact,” and therefore introduces inconsistencies among the industry. AEPC also signed on to ACES comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The proposed Requirement R5, Part 5.6 is in response to a FERC directive (Order 777) to include a communication path for IROL information to the owning entities as part of this project. It was addressed as a subpart of R5, which addresses RC communication requirements of SOLs (including IROLs). The wording in R8 mirrors the definition of IROL since the SDT is replacing references to planning IROLs as they will no longer exist with the retirement of FAC-010. Therefore, the wording in R8 should be interpreted consistently with this intent.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	

Answer	No
Document Name	
Comment	
Alliant Energy supports the comments filed by the MRO NERC Standards Review Forum (NSRF) for this question.	
Likes 0	
Dislikes 0	
Response	
Refer to response to MRO NSRF comments	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	

MPC agrees with and supports the MRO NERC Standards Review Forums comments:

FAC-014-3, Part 5.6

The MRO NSRF notes that FAC-014, Part 5.6 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Reliability Coordinators provide Transmission Owners and Generator Owners with a list of their Facilities identified as critical to the derivation of an IROL and its associated contingencies. If the application of Part 5.6 is intended to include: Operations Planning, ***Same-day Operations and Real-Time Operations (with emphasis on the latter time horizons)***, the MRO NSRF believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard.

If, however, the intent is to limit the time horizon to Operations Planning as indicated in Parts 5.1, 5.2 and 5.4 (tied to Part 5.2), which are limited in their application to "at least once every 12 months," FAC-014 may be the best fit location. If this is the case, the MRO NSRF recommends Part 5.6 be clarified to "at least once every 12 months" and Same-day Operations and Real-Time Operations be stricken from the applicable Time Horizons for Requirement R5 as illustrated below:

R5. Each Reliability Coordinator shall provide: [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months.

Finally, if the deriviation of an IROL and its associated critical contingencies is considered temporary, there is no language in Part 5.6 of the standard that limits when and if CIP-002-5.1a must be applied to these facilities. The MRO NSRF recommends the SDT address this as part of this project as this has the potential to trigger a new Medium Impact Rating for an entity.

Regardless of location, the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28).

FAC-014-3, Requirement 8

The MRO NSRF notes that FAC-014, R8 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Planning Coordinators and Transmission Planners provide Transmission Owners and Generator Owners with a list of their Facilities that comprise planning event Contingencies that would cause instability, Cascading or uncontrolled separation that adversely impact BES reliability as identified in its Planning Assessment. Similar to what is noted above for Part 5.6 , the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28). Without this linkage, Generator Owners receiving information pursuant to FAC-014-3, Requirement 8 for the first time may fail to make the correlation to CIP-002-5.1a.	
Likes 0	
Dislikes 0	
Response	
Refer to response to MRO NSRF comments	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
The addition of the term ‘critical’ to R5.6 makes this revision difficult to support and impossible to ensure compliance. ‘Critical’ is not a defined term in the NERC Glossary - consider removing the term 'critical' or adding term to the NERC Glossary. The term critical was also inserted into R 5.2.4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. “Critical to the derivation of an IROL…” is used commonly in the body of NERC standards. The use in Requirement R5, Part 5.6 is consistent with this practice and would be interpreted/enforced consistently.	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	

I'm supporting MRO NSRF comments:

FAC-014-3, Part 5.6

The MRO NSRF notes that FAC-014, Part 5.6 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Reliability Coordinators provide Transmission Owners and Generator Owners with a list of their Facilities identified as critical to the derivation of an IROL and its associated contingencies. If the application of Part 5.6 is intended to include: Operations Planning, ***Same-day Operations and Real-Time Operations (with emphasis on the latter time horizons)***, the MRO NSRF believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard.

If, however, the intent is to limit the time horizon to Operations Planning as indicated in Parts 5.1, 5.2 and 5.4 (tied to Part 5.2), which are limited in their application to "at least once every 12 months," FAC-014 may be the best fit location. If this is the case, the MRO NSRF recommends Part 5.6 be clarified to "at least once every 12 months" and Same-day Operations and Real-Time Operations be stricken from th applicable Time Horizons for Requirement R5 as illustrated below:

R5. Each Reliability Coordinator shall provide: [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months.

Finally, if the deriviation of an IROL and its associated critical contingencies is considered temporary, there is no language in Part 5.6 of the standard that limits when and if CIP-002-5.1a must be applied to these facilities. The MRO NSRF recommends the SDT address this as part of this project as this has the potential to trigger a new Medium Impact Rating for an entity.

Regardless of location, the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28).

FAC-014-3, Requirement 8

The MRO NSRF notes that FAC-014, R8 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Planning Coordinators and Transmission Planners provide Transmission Owners and Generator Owners with a list of their Facilities that comprise planning event Contingencies that would cause instability, Cascading or uncontrolled separation that adversely impact BES reliability as identified in its Planning Assessment. Similar to what is noted above for Part 5.6 , the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28). Without this linkage, Generator Owners receiving information pursuant to FAC-014-3, Requirement 8 for the first time may fail to make the correlation to CIP-002-5.1a.

Likes 0	
Dislikes 0	

Response

Refer to response to MRO NSRF comments

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

Answer	No
Document Name	

Comment

FAC-014-3, Part 5.6

The MRO NSRF notes that FAC-014, Part 5.6 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Reliability Coordinators provide Transmission Owners and Generator Owners with a list of their Facilities identified as critical to the derivation of an IROL and its associated contingencies. If the application of Part 5.6 is intended to include: Operations Planning, ***Same-day Operations and Real-Time Operations (with emphasis on the latter time horizons)***, the MRO NSRF believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard.

If, however, the intent is to limit the time horizon to Operations Planning as indicated in Parts 5.1, 5.2 and 5.4 (tied to Part 5.2), which are limited in their application to "at least once every 12 months," FAC-014 may be the best fit location. If this is the case, the MRO NSRF recommends Part 5.6 be clarified to "at least once every 12 months" and Same-day Operations and Real-Time Operations be stricken from the applicable Time Horizons for Requirement R5 as illustrated below:

R5. Each Reliability Coordinator shall provide: [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months.

Finally, if the deriviation of an IROL and its associated critical contingencies is considered temporary, there is no language in Part 5.6 of the standard that limits when and if CIP-002-5.1a must be applied to these facilities. The MRO NSRF recommends the SDT address this as part of this project as this has the potential to trigger a new Medium Impact Rating for an entity.

Regardless of location, the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28).

FAC-014-3, Requirement 8

The MRO NSRF notes that FAC-014, R8 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Planning Coordinators and Transmission Planners provide Transmission Owners and Generator Owners with a list of their Facilities that comprise planning event Contingencies that would cause instability, Cascading or uncontrolled separation that adversely impact BES reliability as identified in its Planning Assessment. Similar to what is noted above for Part 5.6 , the Guidelines and Technical Basis for CIP-002-5.1a will

need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28). Without this linkage, Generator Owners receiving information pursuant to FAC-014-3, Requirement 8 for the first time may fail to make the correlation to CIP-002-5.1a.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.The concern with temporary conditions that lead to IROL establishment is well taken and the SDT agrees that temporary IROL conditions are not the appropriate trigger for TO & GO consideration pursuant to CIP-002-5.1a. However, this ambiguity exists today due to the wording in criteria 2.6 of the CIP standard that references specific facilities, identified by the RC (or planning entities) that are critical to the derivation of an IROL. The proposed Requirement R5, Part 5.6 does not change this reality. The SDT is not currently pursuing changes to the CIP standard as these efforts failed in the past when combined with the efforts of an ongoing CIP SDT. It is this SDT's opinion that CIP modifications would be best served by another drafting team, with an appropriate SAR, that can address all issues with the current criteria, some of which are not related to Project 2015-09. Likewise, R8 is in response to the same FERC directive. It is important to note that, without the proposals in Requirement R5, Part 5.6 & R8, there is no requirement for this type of information to be sent to the appropriate owners. Therefore, this is a reliability enhancement as it relates to this communication. The SDT is also adding clarity to the appropriate time horizons in Requirement R5, Part 5.6 with an updated posting of the standard. The SDT is in agreement with the concern on the time horizons related to R5 and is modifying the standard in response.	
Jerry Horner - Basin Electric Power Cooperative - 6	
Answer	No
Document Name	
Comment	
Basin Electric supports the MRO NSRF comments. Jerry Horner	
Likes 0	

Dislikes 0	
Response	
Refer to response to MRO NSRF comments	
Wayne Guttormson - SaskPower - 1	
Answer	No
Document Name	
Comment	
Support the MRO-NSRF comments for R5.6 and M3. Recommend removing Req 8 or addressing the issue directly in CIP 002 or FAC 003. It is unclear how TO's and GO's would use this information as presented otherwise. For FAC-003, with the retirement of FAC-010-3 the PC is not resposible for identifying IROLs, and the language for '**4.2.2.** Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.' should be changed to denote the RC. For CIP-002 '**2.6.** Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.' the reference to PC should be removed.	
Likes 0	
Dislikes 0	
Response	
Refer to response to MRO NSRF comments	

The referenced CIP and FAC standards do not apply to the PC or TP as applicable functional entities. Therefore, the requirement to communicate planning information should be included in a standard applicable to planning entities.	
Kjersti Drott - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State does not believe the revisions provide clear instruction. R5.6 language could be improved within the context of IROL development. 'Critical' to the derivation of an IROL is ambiguous and requires further clarification to ensure uniform interpretation and implementation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. “Critical to the derivation of an IROL…” is used commonly in the body of NERC standards. The use in Requirement R5, Part 5.6 is consistent with this practice and would be interpreted/enforced consistently.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP is supportive of R5.6 as the proposed requirement clearly aligns and supports criteria outlined in CIP-002 and CIP-014. This requirement should remove any previous ambiguities that may have occurred in identifying facilities that are critical to the derivation of an IROL and its associated contingencies. AEP is also supportive of R8 as proposed as this will ensure GO’s and TO’s receive information for Facilities within their systems that could lead to instability/cascading and would create a more clear line of sight for those entities to take action on identified facilities accordingly to reduce potential risk of future instability/cascading. It should be noted however, the Corrective Action Plan and critical facility reports	

proposed within R7 and R8 are direct outcomes of TPL-001-4 requirements and should instead be included in that standard, if in any at all. There is no benefit having requirements pertaining to the reporting of planning studies scattered across different families of standards. 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	
Thank you for your comment. The inclusion of R7 & R8 in the TPL-001 standard was investigated by the SDT and was ultimately not an option that was available to us. Future edits of the TPL-001 standard may take into account moving these requirements but that will occur under another SAR. The suggestions on the redline creation would be under the purview of NERC. The SDT does not control the methodology of the redline document creation.	
Dennis Sismaet - Northern California Power Agency - 6	

Answer	No
Document Name	
Comment	
See prior NCPA and John Allen City Utilities prior balloting comments	
Likes 0	
Dislikes 0	
Response	
Refer to response to referenced comments.	
Michael Whitney - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
See prior NCPA and John Allen City Utilities prior balloting comments.	
Likes 1	Truong Le, N/A, Le Truong
Dislikes 0	
Response	
Refer to response to referenced comments.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes

Document Name	
Comment	
OPG support NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Refer to response to referenced comments.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

EEI agrees that the addition of Requirement R5, part 5.6 enhances and clarifies the obligations of the RC under requirement R5. This change also supports GO and TO CIP compliance activities for CIP-002 and/or CIP-014. However, the reference within the FAC-014-3 Technical Rationale, on the top of page 6, incorrectly references "4.1.1.4 in CIP-014." This reference should be 4.1.1.3 (see below).

Excerpt from FAC-014-3 Technical Rationale, Page 6 (Rationale R5)

Finally, Requirement R5, part 5.6, requires that the RC must provide each impacted Generation Owner or Transmission Owner within its Reliability Coordinator area with a list of Facilities that they can use to satisfy the criteria in Attachment 1 part 2.6 in CIP-002 and/or **4.1.1.4 in CIP-014**. Of the three possible entities, RC, TP and PC listed in CIP-002 and CIP-014 that could deliver this information to the TOs and GOs, the RC is ultimately responsible given they're required to establish IROLs. Thus, the requirement for provision of the list of Facilities identified as critical to the derivation of an IROL and its associated critical contingencies should rest with the RC.

CIP-014-2

Applicability Section 4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner **as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies**. 4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements. EEI supports the modification to Measure M3. EEI supports the changes made to Requirement R8, which address our earlier concerns and provides clear requirements for Planning Coordinators and Transmission Planners that define what they must communicate to impacted TOs and GOs whenever planned contingency events indicate that instability, Cascading and uncontrolled separation would occur resulting in negative impacts to BES reliability in the Near-Term Transmission Planning Horizon.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will pursue corrections to the rationale to correct the CIP criteria reference.	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI commnets	
Likes 0	
Dislikes 0	

Response	
Refer to response to referenced comments.	
Douglas Webb - Evergy - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Evergy incorporates by reference and supports the comments of Edison Electric Institute (EEI) in response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Refer to response to referenced comments.	
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 agree with the revisions, however, please consider revising and renumbering the R5.2 sub-requirements as follows: 5.2.1 The value of the stability limit or IROL; 5.2.2 The associated IROL Tv for any IROL;	

5.2.3 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL and the associated Contingeny(ies); 5.2.4 A description of system conditions associated with the stability limit or IROL; and 5.2.5 The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT notes this comment. Ultimately, the change in numbering was deemed non-substantive and would require a significant number of documents to be re-balloted. Therefore, the SDT chose to leave the numbering as is in the current posting.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comments submitted by the Edison Electric Insititue (EEI). Submitted on behalf of Exelon: Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Refer to response to referenced comments.	
Richard Jackson - U.S. Bureau of Reclamation - 1	

Answer	Yes
Document Name	
Comment	

Requirement R5.6 does not reference any schedule or frequency. Reclamation recommends adding a required communication cycle to align with the language in Requirement R5.2, to ensure that GOs and TOs have access to updated information, and to provide the RCs with greater confidence in responses received from entities that must document the lack of Facilities critical to the derivation of an IROL for CIP-002. Reclamation recommends the following language:

Change from:

Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies.

To:

Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies **at least once every twelve calendar months**.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The periodicity of communication is being addressed in an updated posting of the standard.

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

Answer	Yes
Document Name	
Comment	

In regards to requirement R8, BC Hydro requests that the drafting team confirm if it the intent was to include the extreme events (as referenced on page 11 in Table 1 of TPL-001-4) when determining the "list of Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon"? Including the extreme events for consideration under the FAC-014-3 R8 appears to be an expansion of the current requirement R6 of FAC-014-2, which only references multiple contingencies per TPL-003 (not including extreme events, which were covered in TPL-004 System Performance under Extreme Events prior to TPL-001-4 becoming effective).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The intent is for planning events to be the primary applicability of R8. Inclusion of select extreme events in the applicability is not precluded by this requirement but should be the determination of PC/TP based on their expertise or other applicable factors specific to their respective areas or coordination practices with owners.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
FAC-014-3, R5.6 FAC-014-3, Part 5.6 modifies and expands the existing FAC-014-2 to require Reliability Coordinators provide Transmission Owners and Generator Owners with a list of their Facilities identified as critical to the derivation of an IROL and its associated contingencies.	

Facilities identified as critical to the derivation of an IROL and its associated contingencies is a criterion for applying a Medium Impact Rating under CIP-002-5.1a. The proposed requirement R5.6 is redundant and we suggest that there is no reliability need to expand FAC-014-2 with the proposed R5.6.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The proposed Requirement R5, Part 5.6 is in response to a FERC directive (Order 777) to include a communication path for IROL information to the owning entities as part of this project. It was addressed as a subpart of R5, which addresses RC communication requirements of SOLs (including IROLs)	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
AZPS does not have comments for the revised measurement M3 of FAC-014-3. AZPS does not have comments for the the added requirement 5.6 as it currently does not impact AZPS however may have potential impact in the future. AZPS does not have comments for R8.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Glen Allegranza - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
no comments	
Likes 0	
Dislikes 0	
Response	

Ed Hanson - Pacific Gas and Electric Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jose Avendano Mora - Edison International - Southern California Edison Company - 1	
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	
Karen Weaver - Tallahassee Electric (City of Tallahassee, FL) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Pamalet Mackey - Pamalet Mackey On Behalf of: Ed Hanson, 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	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
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	
Teresa Cantwell - Lower Colorado River Authority - 5	
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	

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	
Sandra Ellis - Pacific Gas and Electric Company - 3 - 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	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you	
Nurul Abser - NB Power Corporation - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you	
Richard Brooks - Reliable Energy Analytics LLC - 8	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you	
Robert Hirchak - Cleco Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Texas RE is concerned there is no timeline for the provision of the list of Facilities in the new Requirement R5.6. Texas RE suggests being consistent with Requirements 5.1 and 5.2 which specify “at least once every twelve calendar months.” Texas RE also recommends capitalizing “Contingency(ies)” since it is defined in the NERC Glossary.

For Requirement R8, Texas RE inquires as to whether it is intended that all lines “that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES” that are communicated to the GO or TO under R8 would be applicable to FAC-003-5. FAC-003-5 section 4.2.2 states “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.”

Texas RE reads this language to require all overhead transmission lines operated below 200 kV communicated by Planning Coordinators and Transmission Planners comprising planning event Contingencies causing instability, Cascading, or uncontrolled separate to remain subject to the FAC-003-5 vegetation management requirements. However, Texas RE is concerned that, for a planning event that involves multiple Contingencies (P3 – P7), the standard could be read to exclude single Facilities associated with the event by virtue of the fact that the loss of the individual Facility does not result, by itself, in instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System. Texas RE believes that such a reading could result in a reliability gap if individual Facilities under 200 kV that contribute to instability, Cascading, or uncontrolled separation in planning studies are arguably not included within the scope of FAC-003-5. Accordingly, Texas RE requests that the SDT clarify that it did not intend to exclude such Facilities from the scope of the FAC-003-5 vegetation management requirements.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The periodicity of communication for Requirement R5, Part 5.6 is being addressed in an updated posting of the standard. The modifications to FAC-014 and related modifications to FAC-003 are replacing the reference to planning IROLs with more appropriate language. The language used incorporates the definition of IROL so the intent is to not change the facilities that are applicable to FAC-003, but rather to correct the reference to those Facilities and provide a mechanism for this information to flow from planners to owners. Additionally, the SDT did not exclude any planning events from being applicable to R7 and R8 so facilities associated with P3 – P7 events should not be excluded with the new wording in the proposed standard revisions.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Refer to response to referenced comments.	
Neil Shockey - Edison International - Southern California Edison Company - 5	
Answer	

Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Refer to response to referenced comments.	
Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you	

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

Michael Whitney - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
See prior NCPA and John Allen City Utilities prior balloting comments.	
Likes 0	
Dislikes 0	
Response	
See response to City Utilities comments.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	
Document Name	
Comment	
See prior John allen and John Allen City Utilities prior balloting comments	
Likes 0	
Dislikes 0	
Response	
See response to City Utilities comments.	

Robert Hirchak - Cleco Corporation - 6	
Answer	
Document Name	
Comment	
No other comments	
Likes 0	
Dislikes 0	
Response	
John Allen - City Utilities of Springfield, Missouri - 4	
Answer	
Document Name	
Comment	
City Utilities of Springfield appreciates the 2015-09 team's consideration of our previous comments. We understand the desire to complete this five year old project, but respectfully disagree that additional changes are not necessary. We believe that current projects should not continue creating requirements that are either unclear, redundant or out of place in the body of Reliability Standards. This is contrary to all the efforts industry is putting forward in the Standards Efficiency Review project. Therefore, City Utilities stands firm on our previous comments.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The drafting team understands the concerns and the responses made to the previous set of comments remains valid.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP is concerned by the usage and meaning of “stability criteria” within R6, and request that the SDT provide clarity regarding the exact meaning of this phrase. Does it mean the acceptable power swing damping level and transient voltage dip and recovery durations? Does it mean the bare necessity for the system to remain stable? Does it mean the P1-P7 contingency definitions used in studies to evaluate stability? Does it mean the stability SOLs themselves? Uncertainty regarding the exact meaning of this phrase leads us to offer the following feedback… If “stability criteria” means stability SOLs themselves, then the following feedback paragraph applies. The RC must deal with real-time outages, often simultaneous multiple outages that may result in more restrictive stability operating limits than are considered in planning studies. Example: the RC secures system against P4 stuck CB events during other real-time outages. In planning, prior outages are not required to be simulated by the TPL standard for P4 events, nor have they been regarded as necessary for P4 event planning purposes in the past. Depending on a RC’s SOL methodology, the proposed R6 may impose more restrictive limits on planning studies, and for this reason, might result in corrective action plans and expense that would not have been identified in the past. R6 may also result in complication and confusion between planning and operations because it may never be clear out of the numerous outage conditions encountered by operations in any day, season, or year, which of these must be considered in planning studies under the proposed R6. It is also quite likely that particular combinations of outages will never appear again, rendering planning studies that are forced to recognize SOLs resulting from such outage combinations as “more limiting stability criteria” not very relevant. If “stability criteria” means the acceptable power swing damping level and transient voltage dip and recovery durations, or the bare necessity for the system to remain stable, or the P1-P7 contingency definitions used in studies to evaluate stability then the following feedback paragraph applies. The RCs, PCs, and TPs most probably already have (and in our experience *do* have) coordinated power swing damping criteria and would have consistent transient voltage criteria should that ever be applied in operations. There is no valid reason to require this in FAC-014. The performance measure requiring system stability to be maintained is the same by definition in both operations	

and planning. Contingency event definitions are also the same between operations and planning. If there are no other stability criteria to be coordinated between RC and PC/TP, the proposed R6 may be useless for stability planning purposes and will only cause needless administrative paperwork.

In addition, real-time generation redispatch is often assumed in planning studies to resolve instability and it is not always considered a Corrective Action Plan. Real-time generation redispatch may be particularly relevant to P6 scenarios as “system adjustments” as distinguished from “corrective action plans.” Thus, real-time redispatch may either result in no corrective action plan because it is not considered a corrective action plan (nullifying R7) or, as a system adjustment, will result in no planning event instability, cascading, or uncontrolled separation (nullifying R8). The reliability benefit of the proposed R7 and R8 may be nullified if generation redispatch is used to resolve instability.

AEP recommends removal of “stability criteria” from the proposed R6 and transfer of the proposed R7 and R8 over to a TPL-001 Standards Drafting Team. While well intentioned, we believe the Project 2015-09 Standards Drafting Team is unintentionally encroaching on the TPL domain by proposing R7 and R8 be placed within FAC-014. These requirements are best served if drafted and reviewed from a Transmission Planner perspective which can properly evaluate their necessity in view of the potential for nullification by possible reliance on operational actions and system adjustments not considered corrective action plans.

While we obviously do not yet know the answers to the “stability criteria” question we have posed above, we would like to propose the following revisions to R6 which we believe may provide clarity and minimize compliance burden...

Each Planning Coordinator and each Transmission Planner shall ~~implement a documented process to~~ ~~use~~ *incorporate* Facility Ratings, System steady-state voltage limits and stability limits ~~criteria~~ in its Planning Assessment of Near Term Transmission Planning Horizon ~~that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its Reliability Coordinator’s SOL methodology~~ *as identified in Requirement 5.1 and 5.2.*

• The Planning Coordinator may *also* use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.

• The Transmission Planner may *also* use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

In the event that the formatting used for our suggested revisions to R6 (showing both our deleted and added text) are not retained by the SBS system, we provide it here again, showing only the retained and added text in a “clean format.”

Each Planning Coordinator and each Transmission Planner shall incorporate Facility Ratings, System steady-state voltage limits and stability limits in its Planning Assessment of Near Term Transmission Planning Horizon as identified in Requirement 5.1 and 5.2.

• The Planning Coordinator may also use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.

• The Transmission Planner may also use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

The compliance burden is minimized by simply requiring the PC/TP to incorporate RC ratings and limits in TPL assessments instead of requiring yet another process document for what should be a straightforward comparison check. Emphasizing Requirements R5.1 and R5.2

in R6 clarifies the responsibility of the PC/TP. R5.1 and R5.2 provide the PC/TP specific SOL/IROL/stability limits from the RC that can be incorporated into Planning Assessments. Only referencing an RC's SOL methodology as originally proposed in R6 could lead to much interpretation by the PC/TP since they are only methodology documents. In addition, from a stability perspective, requiring the PC/TP to evaluate specific stability events as identified by the RC in R5.1/R5.2 provides a finite set of events to be considered for the Planning Assessment. It is possible that some of the stability limits from the RC will not satisfy Planning Assessment criteria, but using R5.1/R5.2 as the point of reference provides structure to the Planning Assessment process.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The term "stability criterion" is common language that is used or synonymous with language elsewhere in the standards, most notably in TPL-001-4. The SDT feels it is sufficient to describe the intent of the requirement. The term "stability criterion" refers to the criterion used to establish stability SOLs and not the SOLs themselves. Which seems to be in line with latter understanding presented. However, there is a need to highlight it within the FAC-014 standard for the purpose of clarity in ensuring Planning criterion is more stringent than Ops criterion for stability as no such requirement exists today and not all Planning and Operating entities are so closely aligned. Regarding the comments to R7 and R8, future consideration will be given to moving R6, R7 and R8 into TPL-001. The suggestion to alleviate perceived "compliance burden" does add structure, but does not fit for entities that do not establish limits within their Planning functions. It does not negate the need for process to use Facility Ratings, System steady-state voltage limits and stability criteria in the Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology,.	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	
Document Name	
Comment	

None	
Likes 0	
Dislikes 0	
Response	
Glen Allegranza - Imperial Irrigation District - 1,3,5,6	
Answer	
Document Name	
Comment	
no comments	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
The current effective standard FAC-014-2 version, Requirement 5.1.3 states “The associated Contingency(ies)”. The proposed FAC-014-3, Requirement 5.2.4, states “The associated critical Contingency(ies).” What distinguishes a “critical” contingency(ies)?	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response given to Dominion Energy.	
Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	
Document Name	
Comment	
No Additional comments	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	
Document Name	
Comment	
R6: Techincal rational seems inconsistent with how the language as written could be read. Requirement does give the RC authority over the PC in it sets a performance requirement for the PC to meet outside of the TPL standard. It seems to pre-suppose that the PC's criteria and the Facility Ratings it uses may be suspect. Suggest the SDT draft language for the RC to simply submit its SOL methodology and ratings and perhaps more importantly the basis to the PC for review and comment. The PC can then determine what is applicable for its planning assessment.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The technical rational did intend to presuppose the PC's criteria may be suspect. The suggestion is welcomed. However, there remains a need to document a process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology, to support an operable real-time system.	
Jerry Horner - Basin Electric Power Cooperative - 6	
Answer	
Document Name	
Comment	
Basin Electric supports the MRO NSRF comments. Jerry Horner	
Likes 0	
Dislikes 0	
Response	
See response to MRO NSRF comments.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

FAC-014-3, Requirement R6

The provided rationale document for Requirement 6 states, "The intent of Requirement 6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor to allow the PCs or TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." The rationale document also states (following on from the earlier quote), "This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology."

From a Planning study perspective, TPL-001-4, Requirement 1, obligates PCs and TPs as part of their Planning Assessment of the Near Term Transmission Planning Horizon to use data consistent with what is provided in accordance with MOD-032.

The MRO NSRF also recommends the following additional changes to the language in the requirement:

{C}· FAC-011-4 uses the phrase, "System Voltage Limits" (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as "System steady state voltage limits" as well as "System Voltage Limits". The MRO NSRF recommends that consistent terminology be used across these standards.

{C}· FAC-011-4 uses the phrases, "stability limits", and "stability performance criteria" (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as "stability criteria" or just "stability". The MRO NSRF recommends that consistent terminology be used across these standards.

Finally, the MRO NSRF recommends that the following change be made to R6 to clarify the intent of the requirement:

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System Voltage Limits and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the use of Facility Ratings, System Voltage Limits and stability criteria described in its respective Reliability Coordinator's SOL methodology.

Requirement 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 are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its Reliability Coordinator's SOL methodology.

FAC-014-3, Requirement 7

As proposed FAC-014-3, R7 is partially duplicative of existing requirements under IRO-017-1, R3 and TPL-001-4, R8 which obligate Planning Coordinators and Transmission Planners to provide Planning Assessments to impacted Reliability Coordinators and adjacent Planning Coordinators and Transmission Planners, respectively. The MRO NSRF requests the SDT update an existing requirement rather than introduce a new requirement so that this type of information is consolidated in a single location. That said, the MRO NSRF recognizes that the information referenced in FAC-014, R7 is not explicitly required under either of the aforementioned standards and the option to reopen TPL has been discussed at length by the SDT. As a decision has been made not to reopen TPL-001 at this time, the MRO NSRF requests TPL-001, R8 be expanded to include Transmission Operators and Reliability Coordinators when it is next reopened for modifications and FAC-014-3, R7 be retired at that time.

FAC-011-4, Part 6.4

Finally, the MRO NSRF requests the SDT confirm in a response to comments or in a Technical Rationale document that **FAC-011-4, Part 6.4**, "planned manual load shedding is acceptable only after all other available System adjustments have been made," only applies to addressing overloads that are observed in a planning or forecasted timeframe and is not intended to address actual overloads in Real-time on the system. This observation is made based on the Time Horizon for R6; i.e. 'Operations Planning,' and the descriptor of "*planned*" manual load shedding.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. It is unclear what is recommended in the first paragraph of the comments (if anything) as the second paragraph starts off with, "The MRO NSRF also recommends…"

The terms "system steady-state voltage" and "stability criterion" use common language that is used or synonymous with language elsewhere in the standards, most notably in TPL-001-4. The SDT feels they are sufficient to describe the intent of the requirement.

Regarding the comments to R7 and R8, future consideration will be given to moving R6, R7 and R8 into TPL-001.

Thank you for your comment regarding Part 6.4. The SDT agrees in principle with the commenter. FAC-011-4 Part 6.4 refers to requirements that should be in the RC methodology. Through those requirements, it guides the Operating Plans developed by the RC and TOP in their Real-time Assessment and the Operational Planning Analysis, which would be the “planned” actions. The response by an operator to an event in Real-time monitoring would be based on those Operating Plans but part 6.4 would not directly apply to those real time actions. The RC’s methodology can provide further clarity when addressing part 6.4.

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 – WECC	
Answer	
Document Name	
Comment	

R6:

The SDT agreed with BPA’s previous comments to the proposed revisions.The SDT noted that the Technical Rationale would be revised to ensure this clarity was captured and explained. BPA’s concern is that the Technical Rationale is apart from the Standard and would likely not be used by the auditors. BPA believes this language needs to be explicitly stated in the Standard.

Additionally, after further review of the SDT’s proposed language, BPA does not agree with using the term “criteria” before Facility Ratings.

SDT Proposed Language for 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 are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

BPA recommends the following edits to add clarity to the STD's proposed R6 revisions. BPA also believes '***system voltage limits'*** should not be capitalized, as it is not defined in the NERC Glossary of Terms. (Bold, italic text for additions):

R6. Each Planning Coordinator and each Transmission Planner shall ***ensure that Facility Ratings and system voltage limits*** *used* in its Planning Assessment of the Near Term Transmission Planning Horizon are equally limiting or more limiting than the ***Facility Ratings and system voltage limits provided by the TOP to its RC in accordance with*** its Reliability Coordinator's SOL methodology. ***In addition, each Planning Coordinator and each Transmission Planner shall ensure that criteria developed and documented for stability performance for its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the criteria for stability specified in its respective Reliability Coordinator's SOL methodology.*** *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

BPA has no suggested changes to the R6 bullets below.

• The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.

• The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

R7:

BPA appreciates the SDT incorporating the language *"…that adversely impacts the reliability of the Bulk Electric System…"* into the modified R8. BPA's other comments were in response to Corrective Action Plans. BPA does not believe that the addition of language in R8 satisfies our concerns with R7. BPA believes R8 is a subset of R7.4 where R7.4 is related to the contingency event, and R8 is related to the facilities that comprise the contingency event.

BPA believes it should only be required to communicate/report information for Corrective Action Plans to impacted Transmission Operators and Reliability Coordinators that adversely impact the reliability of the Bulk Electric System. Corrective Action Plans for local issues within a TP's system that do not impact the reliability of the Bulk Electric System should not have to be communicated/reported. As R7 is currently

written, all Corrective Action Plans would need to be communicated/reported. This is consistent with the SDT's response to comments from earlier postings. BPA suggests modifying R7 with the following language below (bold, italic text added) to avoid the burden of communicating/reporting on local issue Corrective Action Plans. By making this change, enitities will only be required to report Corrective Action Plans that affect the larger BES. 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	
Thank you for your comments. Regarding R6, the suggestion is welcomed; however, the SDT feels there is a need to document a process and the word "ensure" does not given enough description of how to execute a requirement. "System Voltage Limits" was a defined term introduced in recently passed balloting associated with proposed FAC-011-4. The suggestion for R7 is appreciated; however, CAPs are sufficiently described in TPL-001-4 such that this additional language is not required.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	

Draft 3 of this standard added requirements for the quality of transmission assessments performed per TPL-001. In particular, R6 calls for Near Term Transmission Planning to use Facility Ratings and Voltage Limits that are equally or more limiting than in the Reliability Coordinator's SOL methodology. Also, R7 calls for Planning Coordinators and Transmission Planners to annually communicate selected results of the Near-Term Transmission Planning results with Transmission Operators and Teliability Coordinators. Ideally, requirements R6 and R7 need to be in TPL-001 instead of FAC-014.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Future consideration will be given to moving R6, R7 and R8 into TPL-001.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	
Document Name	
Comment	
FAC-014-3, Requirement R6 The provided rationale document for Requirement 6 states, "The intent of Requirement 6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor to allow the PCs or TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." The rationale document also states (following on from the earlier quote), "This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology."	

From a Planning study perspective, TPL-001-4, Requirement 1, obligates PCs and TPs as part of their Planning Assessment of the Near Term Transmission Planning Horizon to use data consistent with what is provided in accordance with MOD-032.

The MRO NSRF also recommends the following additional changes to the language in the requirement:

- FAC-011-4 uses the phrase, “System Voltage Limits” (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as “System steady state voltage limits” as well as “System Voltage Limits”. The MRO NSRF recommends that consistent terminology be used across these standards.
- FAC-011-4 uses the phrases, “stability limits”, and “stability performance criteria” (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as “stability criteria” or just “stability”. The MRO NSRF recommends that consistent terminology be used across these standards.

Finally, the MRO NSRF recommends that the following change be made to R6 to clarify the intent of the requirement:

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System Voltage Limits and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the use of Facility Ratings, System Voltage Limits and stability criteria described in its respective Reliability Coordinator’s SOL methodology.

FAC-014-3, Requirement 7

As proposed FAC-014-3, R7 is partially duplicative of existing requirements under IRO-017-1, R3 and TPL-001-4, R8 which obligate Planning Coordinators and Transmission Planners to provide Planning Assessments to impacted Reliability Coordinators and adjacent Planning Coordinators and Transmission Planners, respectively. The MRO NSRF requests the SDT update an existing requirement rather than introduce a new requirement so that this type of information is consolidated in a single location. That said, the MRO NSRF recognizes that the information referenced in FAC-014, R7 is not explicitly required under either of the aforementioned standards and the option to reopen

TPL has been discussed at length by the SDT. As a decision has been made not to reopen TPL-001 at this time, the MRO NSRF requests TPL-001, R8 be expanded to include Transmission Operators and Reliability Coordinators when it is next reopened for modifications and FAC-014-3, R7 be retired at that time.

FAC-011-4, Part 6.4

Finally, the MRO NSRF requests the SDT confirm in a response to comments or in a Technical Rationale document that **FAC-011-4, Part 6.4**, "planned manual load shedding is acceptable only after all other available System adjustments have been made," only applies to addressing overloads that are observed in a planning or forecasted timeframe and is not intended to address actual overloads in Real-time on the system. This observation is made based on the Time Horizon for R6; i.e. 'Operations Planning,' and the descriptor of "*planned*" manual load shedding.

Likes 0	
Dislikes 0	
Response	
Please see the response to MRO NSRF	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	

Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	

Dominion Energy suggests modifying the term “an instability”, as contained in Requirement R4, to “an identified instability”. This proposed change makes Requirement R4 clear that the intent is for the RC to act on identified instability, not after an instability event has occurred.

Dominion Energy requests the SDT clarify the addition of the word “critical” to describe Contingency(ies)” noting that “critical Contingency(ies)” is undefined and opens Requirement R5, subpart 5.2.4 to interpretation. For Dominion Energy to support this change, the term “critical Contingency(ies)” need to be clarified or removed.

Alternatively, the SDT could consider revising the supporting subparts of 5.2 (Requirement R5), as indicated below, as a possible solution to the use of the undefined term “critical Contingency(ies)”.

5.2.1 The value of the stability limit or IROL;

5.2.2 The associated IROL Tv for any IROL;

5.2.3 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL **and the associated Contingency(ies)**;

5.2.4 A description of system conditions associated with the stability limit or IROL; and

5.2.5 The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

Dominion Energy disagrees with the inclusion of “as established in FAC-011-4” within the Severe VSL level within FAC-014-3, Requirement R1. Since requirements can be moved out of one Reliability Standard to another, modified, or retired, this creates a burden to ensure all

references are identified when modifications are made. Each Reliability Standard should stand on its own and should not contain linkage to other Reliability Standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Requirement R4 has been updated as per your suggestion. The term "critical" is used throughout the standards especially pertaining to facilities. As Contingencies can comprise of such facilities, the SDT believes the language proposed in requirement part 5.2 is clear. The FAC-014-3 VSLs have been revised as per your comments.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	
Document Name	
Comment	
FAC-014-3, Requirement R6 The provided rationale document for Requirement 6 states, "The intent of Requirement 6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor to allow the PCs or TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." The rationale document also states (following on from the earlier quote), "This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology."	

From a Planning study perspective, TPL-001-4, Requirement 1, obligates PCs and TPs as part of their Planning Assessment of the Near Term Transmission Planning Horizon to use data consistent with what is provided in accordance with MOD-032.

The MRO NSRF also recommends the following additional changes to the language in the requirement:

· FAC-011-4 uses the phrase, "System Voltage Limits" (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as "System steady state voltage limits" as well as "System Voltage Limits". The MRO NSRF recommends that consistent terminology be used across these standards.

· FAC-011-4 uses the phrases, "stability limits", and "stability performance criteria" (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as "stability criteria" or just "stability". The MRO NSRF recommends that consistent terminology be used across these standards.

Finally, the MRO NSRF recommends that the following change be made to R6 to clarify the intent of the requirement:

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System Voltage Limits and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the use of Facility Ratings, System Voltage Limits and stability criteria described in its respective Reliability Coordinator's SOL methodology.

FAC-014-3, Requirement 7

As proposed FAC-014-3, R7 is partially duplicative of existing requirements under IRO-017-1, R3 and TPL-001-4, R8 which obligate Planning Coordinators and Transmission Planners to provide Planning Assessments to impacted Reliability Coordinators and adjacent Planning Coordinators and Transmission Planners, respectively. The MRO NSRF requests the SDT update an existing requirement rather than introduce a new requirement so that this type of information is consolidated in a single location. That said, the MRO NSRF recognizes that

the information referenced in FAC-014, R7 is not explicitly required under either of the aforementioned standards and the option to reopen TPL has been discussed at length by the SDT. As a decision has been made not to reopen TPL-001 at this time, the MRO NSRF requests TPL-001, R8 be expanded to include Transmission Operators and Reliability Coordinators when it is next reopened for modifications and FAC-014-3, R7 be retired at that time. **FAC-011-4, Part 6.4** Finally, the MRO NSRF requests the SDT confirm in a response to comments or in a Technical Rationale document that **FAC-011-4, Part 6.4**, "planned manual load shedding is acceptable only after all other available System adjustments have been made," only applies to addressing overloads that are observed in a planning or forecasted timeframe and is not intended to address actual overloads in Real-time on the system. This observation is made based on the Time Horizon for R6; i.e. 'Operations Planning,' and the descriptor of "*planned*" manual load shedding.	
Likes 0	
Dislikes 0	
Response	
Please see the response to the MRO NSRF comments.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	
Alliant Energy supports the comments filed by the MRO NERC Standards Review Forum (NSRF) for this question.	
Likes 0	

Dislikes 0	
Response	
Please see the response to the MRO NSRF comments.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Jamie Johnson - California ISO - 2	
Answer	
Document Name	
Comment	
CAISO agrees with comments submitted by the ISO/RTO Council (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	
Response	
Please see the response to the IRC comments.	

Neil Shockey - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see the response to the EEI comments.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
MISO supports comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC) and MRO NERC Standards Review Forum (MRO NSRF).	
Likes 0	
Dislikes 0	
Response	
Please see the response to the IRC and MRO NSRF comments.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	

Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see the response to the EEI comments.	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	
Document Name	
Comment	
N/A - Entergy supports MISO's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response to the MISO comments.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	

NIPSCO endorses the other comments on R6, R7, and R8 provided by AEP on 11/24/2020. And reiterates our prior NIPSCO comments provided 7/31/2020.	
Likes 0	
Dislikes 0	
Response	
Please see the response to the AEP comments.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE has the following comments, noted by section.

Implementation Plan – Effective Date sectionn

- There is a missing delimiter (“) around System Operating Limit (shows *“System Voltage Limit” and System Operating Limit”* but should be *“System Voltage Limit” and “System Operating Limit”*).

Implementation Plan - Prior Implementation Plans section:

- PRC-005-3 is referenced and it seems that it should reference PRC-005-6.
- Texas RE recommends noting that there have been changes to the language of FAC-003-5 to include the TP as an entity that can designate a line and also uses the language “identified the line in Applicability under 4.2” instead of “designates the line as being an element of an IROL”. Texas RE agrees this change should not significantly modify the application of the implementation plan.

- For FAC-003-5 “Newly Designated Lines” - There seems to be some ambiguity about what happens to the lines newly designated under FAC-003-4 Applicability Section 4.2 language in the last year of applicability for FAC-003-4. Do those lines receive an additional year of non-applicability because the new version of the Standard is being applied?
- For PRC-002-3, “TO” and “RC” should be spelled out to be consistent.

Implementation Plan - Additional Provisions section:

- For FAC-014-3 Requirement R6, Texas RE recommends a clear date by which the Planning Assessment must reflect the implementation of Requirement R6 (e.g 24 calendar months after effective date). The language “when it begins its next cycle for conducting the studies to support its Planning Assessment” for R6 is not measureable and may lead to inconsistent understanding and application.

Additional FAC-014-3 Comments:

- Texas RE noticed the SDT added the word “critical” in in FAC-014-3 5.2.4. Texas RE is concerned that since there is no criteria or definition of the word critical, inconsistencies could arise between entities regarding the meaning of “critical” which, in turn, could lead to perceived inconsistencies in monitoring. Texas RE recommends drafting clear criteria to determine “critical” to ensure reliability. While it was added to accommodate the 5.6 language addition there is no clear meaning of the word or intent. When reviewed in audit space there will be a need to understand what “critical” means to an entity and how they derived, and applied, the thought process.
- In Requirement R6, there should be a hyphen in “Near Term”. This is consistent with the NERC Glossary Term.

Texas RE continues to be concerned with the following:

- The asterisk on FAC-003 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.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Corrections to references and characters are appreciated and have been addressed. The implementation date for FAC-014-3 R6 has been clarified. The term "critical" is used throughout the standards especially pertaining to facilities. As Contingencies can comprise of such facilities, the SDT believes the language proposed in requirement part 5.2 is clear. Your comments in relation to FAC-003 have been noted for future consideration.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	
Document Name	
Comment	
For Requirements R5 and R8, Reclamation recommends that the SDT consider adding an annual notice to the TOs and GOs that do not own impacted Facilities. This would increase transparency and provide direct evidence of the lack of impact.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. While this notice would be a nice gesture, the SDT feels that as part of a Requirement, it would not amount to a material benefit in light of the effort.	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	

Southern Company disagrees with the revision to R4. The revision creates unnecessary confusion compared to the original language, seeming to imply that each Reliability Coordinator shall establish stability limits only after an instability event that impacts adjacent Reliability Coordinator Areas has occurred. As such, if the revision is to remain, the following revision is suggested to clarify that this is a proactive coordination, not reactive:

Revise from “an instability” to “an *identified* instability”.

Southern Company disagrees with Requirement R5.2.2, as the modifications to the requirement create unnecessary ambiguity. Specifically, Southern Company disagrees with the inclusion of the word “derivation” in R5.2.2 as there can be a significant number of Facilities across the Interconnections needed to accurately model and simulate a stability event and therefore are critical to the “derivation” of a stability limit. It is suggested instead that “derivation” be defined or replaced with “establishment” to better clarify those Facilities that should be identified.

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.

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:”.
- Add another sentence at the end of R8, as also suggested in Comment Form Question 2 above: “Planning Coordinators and Transmission Planners that do not identify any Facilities are not required to perform the annual communication”.

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Requirement R4 has been updated as per your suggestion. The term "derivation" is used throughout the standards especially pertaining to operating limits. The SDT believes the language proposed in requirement part 5.2.2 is clear. The SDT considered the suggestion provided for R7 and R8; however, it's felt this type of clarity if required can be specified in PC/TP procedures in agreement with the RC/TOP or TO/GO, respectively. Future consideration will be given to moving R6, R7 and R8 into TPL-001.	
Daniel Gacek - Exelon - 1	
Answer	
Document Name	
Comment	
Exelon concurs with the comments submitted by the Edison Electric Insititue (EEI). Submitted on behalf of Exelon: Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Please see the response to the EEI comments.	
sean erickson - Western Area Power Administration - 1	
Answer	

Document Name	
Comment	
thank you	
Likes 0	
Dislikes 0	
Response	
You are welcome.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	
Document Name	
Comment	
FAC-014-3 Comments **Requirement 6** The provided rationale document for Requirement 6 states, "The intent of Requirement 6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor to allow the PCs or TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." The rationale document also states (following on from the earlier quote), "This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology." In consideration of the RC SOL methodology to be provided per the draft FAC-001-4, Requirement 2 states, "each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings."	

The IRC SRC agrees with previously provided comments from the IRC SRC that several standards (such as FAC-008 and MOD-032) place the obligations of determining Facility Ratings on GOs and TOs. Additionally, from a Planning study perspective TPL-001-4 Requirement 1 obligates PCs and TPs as part of their Planning Assessment of the Near Term Transmission Planning Horizon to use data consistent with what is provided in accordance with MOD-032.

In its reply to comments submitted by the IRC SRC, the Standard Drafting Team (SDT) states that they understand the perception of redundancy of this requirement as compared to other NERC Standards, but industry and regulatory comments/inputs moved the SDT down the current path of including Facility Ratings as part of R6. Further, the SDT recognizes the facility owner's responsibility in providing Facility Ratings per FAC-008 and that this does not conflict with what is proposed in FAC-014. The IRC SRC recommends that by including the Facility Ratings requirement in other standards (such as MOD-032), increased benefit is seen across additional standards and not just the Planning Assessment of Near-Term Transmission Planning Horizon.

The IRC SRC also recommends the following additional changes to the language in the requirement:

- FAC-011-4 uses the phrase, "System Voltage Limits" (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as "System steady state voltage limits" as well as "System Voltage Limits". The IRC SRC recommends that consistent terminology be used across these standards.
- FAC-011-4 uses the phrases, "stability limits", and "stability performance criteria" (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as "stability criteria" or just "stability". The IRC SRC recommends that consistent terminology be used across these standards.

Finally, the IRC SRC recommends that the following ***change*** be made to R6 to clarify the intent of the requirement:

R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, ***System Voltage Limits*** and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the ***use of*** Facility Ratings, System Voltage Limits and stability ***criteria*** described in its respective Reliability Coordinator's SOL methodology.

Requirement 7

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. The IRC SRC recommended IRO-017-1, R3 be updated so that this type of request is located in a single requirement or standard. The SDT response to this request is that the IRO-17 standard deals with outage coordination (and not SOLs) that FAC-014 is the proper place for SOL transmittal and related information between entities. Additionally, the SDT acknowledges that they discussed at length the annual planning assessment created per TPL-001, and noted that the information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability. The IRC SRC disagrees as the information required in FAC-014 R7 is included in TPL-001 assessments. Requirement 2.7 of TPL-001 requires that the assessment identify the Corrective Action Plan for instances where the analysis indicates the inability to meet the performance requirements. Obligating the Planning Coordinator and Transmission Planner to only communicate Corrective Action Plans for instability issues falls short of information that would be important for Transmission Operators and Reliability Coordinators. As such, updated TPL-001 to provide the report in its entity to Transmission Operators and Reliability Coordinators provides a more holistic view of all Corrective Action Plans that may be forthcoming to the system. As such, the IRC SRC recommends that TPL-001 R8 be modified to specifically include Transmission Operators and Reliability Coordinators.

FAC-011-4

Finally, the IRC SRC would like the drafting team to confirm in a response to comments or the technical rational document that FAC-011-4, Part 6.4 only applies to addressing overloads that are observed in a planning or forecasted timeframe and Part 6.4 would not restrict the RC from taking actions in Real-time if the planned mitigating actions are ineffective or insufficient to address an impending IROL exceedance. This observation is made based on the reference to time horizon being identified as ‘Operations Planning’ and the use of *planned* manual load shedding

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

The term “system steady-state voltage” is used in TPL-001-4 and is associated with the Planning Assessment as it is used in the proposed FAC-14-3 R6; therefore, the SDT feels it should not create confusion in regards to the intent of the requirement. In addition, the terms

"stability" or "stability criteria" are used throughout the standards and the SDT does not feel that using them in the context set out in R6 creates confusion. Regarding the comments pertaining to facility ratings, MOD-32 and R7 and R8, future consideration will be given to these requirements moving into other standards. The comment regarding FAC-011-4 part 6.4 has been addressed in line with your request.

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	

Please consider if revisions to section "C. Compliance" are necessary to update FAC-014-3 with the current NERC wording for the Compliance section. For example, "Compliance Enforcement Authority" could be abbreviated as CEA in the Compliance section.

RE: Violation Severity Levels, R1, Severe VSL: Please consider removing, "as established in FAC-011-4" since this reference appears to be unnecessary.

RE: Technical Rationale for Reliability Standard FAC-014-3, Rationale R5, part 5.6: Please consider correcting the reference to 4.1.1.4 in CIP-014 to read as 4.1.1.3 in CIP-014.

Requirement 6

The provided rationale document for Requirement 6 states, "The intent of Requirement 6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor to allow the PCs or TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." The rationale document also states (following on from the earlier quote), "This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology." In consideration of the RC SOL methodology to be provided per the draft FAC-001-4, Requirement 2 states, "each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings."

NPCC RSC believes that several standards (such as FAC-008 and MOD-032) place the obligations of determining Facility Ratings on the GO and/or TO. Additionally, from a Planning study perspective, TPL-001-4 Requirement 1 obligates PCs and TPs as part of their Planning Assessment of the Near Term Transmission Planning Horizon to use data consistent with what is provided in accordance with MOD-032.

In its reply to the previous comments from the SRC IRC, the Standard Drafting Team (SDT) states that they understand the perception of redundancy of this requirement as compared to other NERC Standards, but industry and regulatory comments/inputs moved the SDT down the current path of including Facility Ratings as part of R6. Further, the SDT recognizes the facility owner's responsibility in providing Facility Ratings per FAC-008 and that this does not conflict with what is proposed in FAC-014. NPCC RSC recommends that by including the Facility Ratings requirement in other standards (such as MOD-032), increased benefit is seen across additional standards and not just the Planning Assessment of Near-Term Transmission Planning Horizon.

NPCC RSC also recommends the following additional changes to the language in the requirement:

{C}·	FAC-011-4 uses the phrase, "System Voltage Limits" (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as "System steady-state voltage limits" as well as "System Voltage Limits". We recommend that consistent terminology be used across these standards.

{C}·	FAC-011-4 uses the phrases, "stability limits", and "stability performance criteria" (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as "stability criteria" or just "stability". We recommend that consistent terminology be used across these standards.

Finally, NPCC RSC recommends that the following change be made to R6 to clarify the intent of the requirement:

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System Voltage Limits and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for use of Facility Ratings, System Voltage Limits and stability criteria described in its respective Reliability Coordinator's SOL methodology.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Those pertaining to the FAC-014-3 VSL and rationale have been addressed. The SDT believes the de-lineation between proposed FAC-014-3 regarding the use of the Facility ratings vs. the determination of the ratings themselves is clear in the requirement and rationale. Regarding the comments pertaining to facility ratings, MOD-32 and R7 and R8, future consideration will be given to these requirements moving into other standards The term "system steady-state voltage" is used in TPL-001-4 and is associated with the Planning Assessment as it is used in the proposed FAC-14-3 R6; therefore, the SDT feels it should not create confusion in regards to the intent of the requirement. In addition, the terms "stability" or "stability criteria" are used throughout the standards and the SDT does not feel that using them in the context set out in R6 creates confusion.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP RTO	
Answer	
Document Name	
Comment	

N/A	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Evergy - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Evergy incorporates by reference and supports the comments of Edison Electric Institute (EEI) in response to Question 3.	
Likes 0	
Dislikes 0	
Response	
Please see the response to the EEI comments.	
David Jendras - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren agrees with and supports EEI commnets	
Likes 0	

Dislikes 0	
Response	
Please see the response to the EEI comments.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	

NV Energy supports MRO NSRF's additional comments:

FAC-014-3, Requirement R6

The provided rationale document for Requirement 6 states, "The intent of Requirement 6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor to allow the PCs or TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." The rationale document also states (following on from the earlier quote), "This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology."

From a Planning study perspective, TPL-001-4, Requirement 1, obligates PCs and TPs as part of their Planning Assessment of the Near Term Transmission Planning Horizon to use data consistent with what is provided in accordance with MOD-032.

The MRO NSRF also recommends the following additional changes to the language in the requirement:

- FAC-011-4 uses the phrase, "System Voltage Limits" (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as "System steady state voltage limits" as well as "System Voltage Limits". The MRO NSRF recommends that consistent terminology be used across these standards.

- FAC-011-4 uses the phrases, “stability limits”, and “stability performance criteria” (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as “stability criteria” or just “stability”. The MRO NSRF recommends that consistent terminology be used across these standards.

Finally, the MRO NSRF recommends that the following change be made to R6 to clarify the intent of the requirement:

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System Voltage Limits and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the use of Facility Ratings, System Voltage Limits and stability criteria described in its respective Reliability Coordinator’s SOL methodology.

FAC-014-3, Requirement 7

As proposed FAC-014-3, R7 is partially duplicative of existing requirements under IRO-017-1, R3 and TPL-001-4, R8 which obligate Planning Coordinators and Transmission Planners to provide Planning Assessments to impacted Reliability Coordinators and adjacent Planning Coordinators and Transmission Planners, respectively. The MRO NSRF requests the SDT update an existing requirement rather than introduce a new requirement so that this type of information is consolidated in a single location. That said, the MRO NSRF recognizes that the information referenced in FAC-014, R7 is not explicitly required under either of the aforementioned standards and the option to reopen TPL has been discussed at length by the SDT. As a decision has been made not to reopen TPL-001 at this time, the MRO NSRF requests TPL-001, R8 be expanded to include Transmission Operators and Reliability Coordinators when it is next reopened for modifications and FAC-014-3, R7 be retired at that time.

FAC-011-4, Part 6.4

Finally, the MRO NSRF requests the SDT confirm in a response to comments or in a Technical Rationale document that **FAC-011-4, Part 6.4**, “planned manual load shedding is acceptable only after all other available System adjustments have been made,” only applies to addressing overloads that are observed in a planning or forecasted timeframe and is not intended to address actual overloads in Real-time on the

system. This observation is made based on the Time Horizon for R6; i.e. 'Operations Planning,' and the descriptor of "*planned*" manual load shedding	
Likes 0	
Dislikes 0	
Response	
Please see the response to the MRO NSRF comments.	
Jose Avendano Mora - Edison International - Southern California Edison Company - 1	
Answer	
Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Please see the response to the EEI comments.	
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	
None and thank you for the opportunity to comment.	
Likes 0	

Dislikes 0	
Response	
You are welcome.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

EEI suggests modifying the term "an instability", as contained in Requirement R4, to "an identified instability". This proposed change makes Requirement R4 clear that the intent is for the RC to act on identified instability, not after an instability event has occurred.

EEI requests the SDT clarify the addition of the word "critical" to describe Contingency(ies)" noting that "critical Contingency(ies)" is undefined and opens Requirement R5, subpart 5.2.4 to interpretation. For EEI to support this change, the term "critical Contingency(ies)" need to be clarified or removed.

Alternatively, the SDT could consider revising the supporting subparts of 5.2 (Requirement R5), as indicated below, as a possible solution to the use of the undefined term "critical Contingency(ies)".

5.2.1 The value of the stability limit or IROL;

5.2.2 The associated IROL Tv for any IROL;

5.2.3 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL **and the associated Contingency(ies)**;

5.2.4 A description of system conditions associated with the stability limit or IROL; and

5.2.5 The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

EEI disagrees with the inclusion of "as established in FAC-011-4" within the Severe VSL level within FAC-014-3, Requirement R1. Since requirements can be moved out of one Reliability Standard to another, modified, or retired, this creates a burden to ensure all references are identified when modifications are made. Each Reliability Standard should stand on its own and should not contain linkage to other Reliability Standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Requirement R4 has been updated as per your suggestion. The term "critical" is used throughout the standards especially pertaining to facilities. As Contingencies can comprise of such facilities, the SDT believes the language proposed in requirement part 5.2 is clear. The FAC-014-3 VSLs have been revised as per your comments.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG support NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response to the NPCC comments.	
Ed Hanson - Pacific Gas and Electric Company - 5	

Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	